ExxonMobil Exploration Company ("ExxonMobil")

RD&D Lease Plan of Operations

This Plan of Operations for Oil Shale Research Development and Demonstration (RD&D) Tract contains ExxonMobil's responses to each of the requirements as requested by the Bureau of Land Management (BLM). The Plan of Operations presented below is a forward-looking description of activities that are subject to change in the future due to new information, better understanding of technical issues, technology breakthroughs and other contingencies. The Plan of Operations provides fairly specific information in some sections and is by necessity conceptual in other areas pending further technical evaluation.

1 NAMES, ADDRESSES AND TELEPHONE NUMBERS OF THOSE RESPONSIBLE FOR OPERATIONS TO BE CONDUCTED UNDER THE APPROVED PLAN TO WHOM NOTICES AND ORDERS ARE TO BE DELIVERED

ExxonMobil's contact representative for the conduct of operations on the research, development, and demonstration (RD&D) lease is:

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2 NAMES AND ADDRESSES OF SURFACE AND MINERAL OWNERS OF RECORD, IF OTHER THAN THE UNITED STATES

Land ownership and surface management of the nominated Section 34 (NE/4) T1S, R98W, RD&D lease tract are managed by the Bureau of Land Management (BLM). This acreage overlaps an existing oil and gas lease administered by the BLM.

3 A DETAILED DESCRIPTION, AND MAPS WHERE APPROPRIATE, OF THE FOLLOWING: GEOLOGIC/HYDROLOGIC CONDITIONS WITHIN THE LEASE TRACT

3.1 PHYSIOGRAPHY OF THE RD&D LEASE

The ExxonMobil oil shale research, development and demonstration (RD&D) lease tract is located in the NE ¼ of Section 34, T1S, R98W. It consists of lots 1, 2, 7 and 8. Total acreage on this RD&D lease is 155.82 acres. The remainder of Section 34, totaling 476.32 acres is reserved as ExxonMobil's preference right lease. Figure 3-1 illustrates the location of the RD&D lease tract within the broad confines of the Piceance Basin. Figure 3-2 provides a more detailed topographic map of the lease tract and the immediately surrounding area.

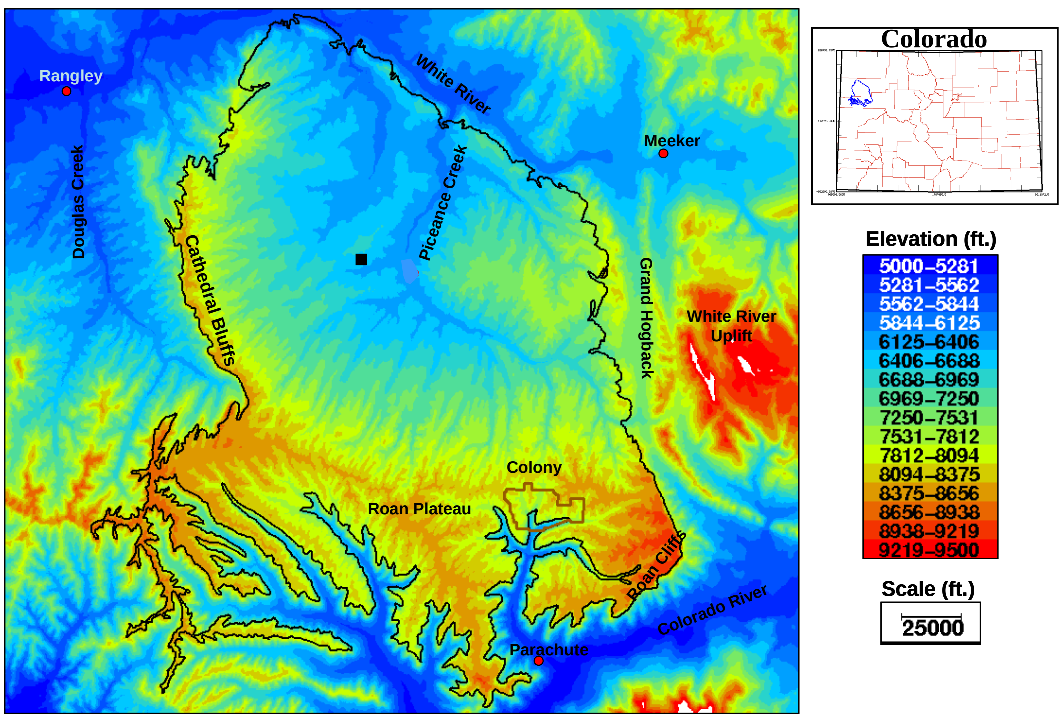


Figure 3-1 Piceance Basin Topographic Map Showing Elevation and Major Topographic Features

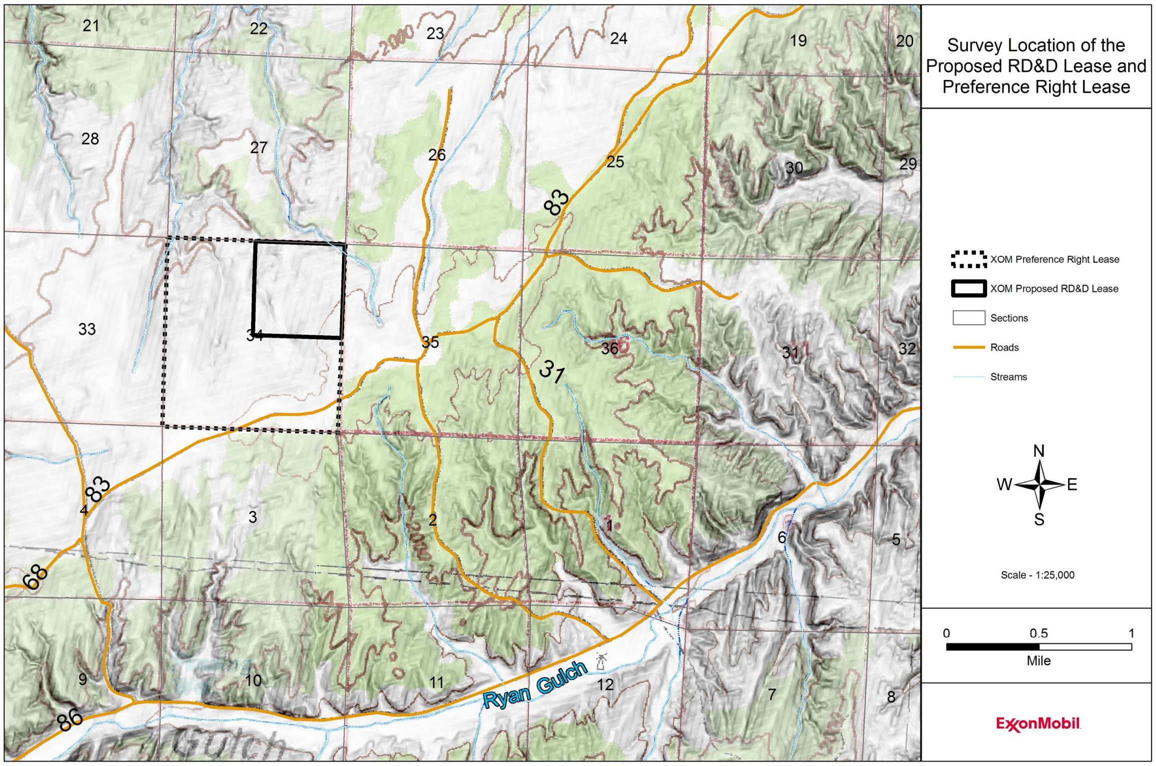


Figure 3-2: Location of Proposed RD&D Lease and Preference Right Lease

The RD&D and preference right lease tracts are located upon the north sloping ridge separating Ryan Gulch from Yellow Creek within the White River Basin. Average elevation of this tract is approximately 2025 m (6642 ft) with an elevation range of between 1990 m (6527 ft) and 2055 m (6740 ft). Average grade is 3-6 %, sloping to the north-northwest.

The lease tract is located within a mixture of land cover types. Part of the lease is occupied by sagebrush/grassland areas. Other portions are covered with pinyon/juniper shrubs and trees. The soil is not classified as fragile or highly erodible.

There are four intermittent stream beds that originate within the RD&D lease tract. These four streams only flow during spring snow melt and during summer thundershowers. All these streams flow into tributaries of Yellow Creek.

3.2 GEOLOGY OF THE RD&D LEASE TRACT

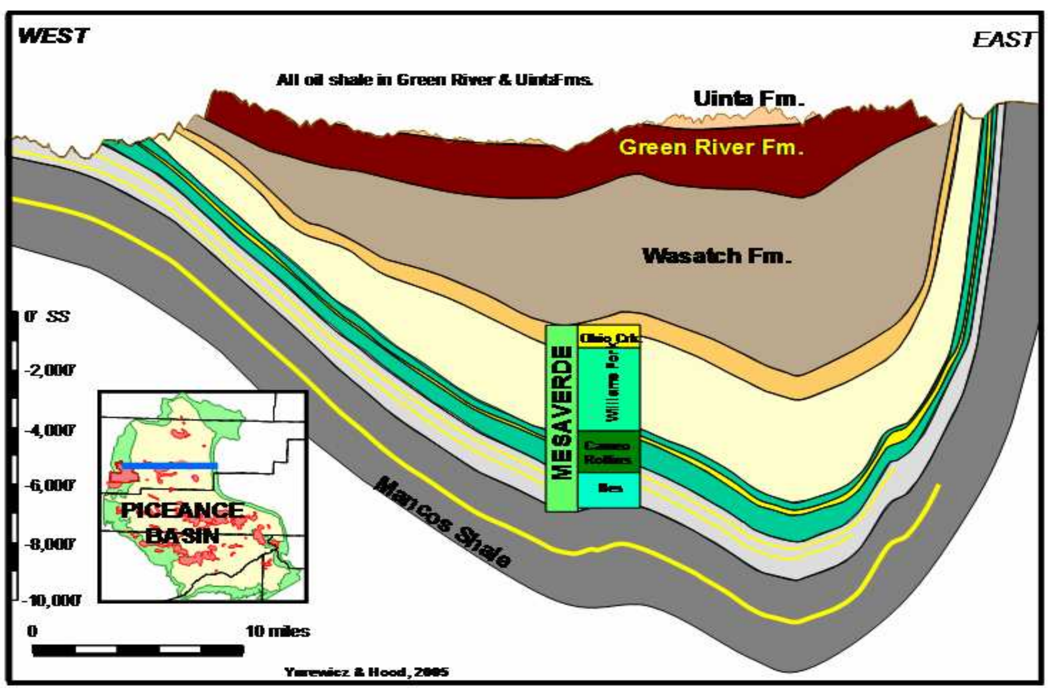
The RD&D lease tract is located within the Piceance Creek Basin of northwestern Colorado. The Piceance Creek Basin is used to describe the part of the Piceance structural basin that is bordered by the Colorado River to the south, the White River to the north, the Grand Hogback to the east, and the Douglas Creek Arch to the west. This portion of the basin consists of approximately 2,572 sq mi in Garfield and Rio Blanco counties (Weeks et al., 1974). Figure 3-1 illustrates the location and topography of the Piceance Creek Basin.

The Piceance Creek basin is a large synclinal structure. Figure 3-3 shows the subsurface geology and structure in the basin. Rock units outcrop on all four sides of the basin though they are very steeply dipping to the west, along the eastern side of the basin.

The relevant units for oil shale development include the Green River Formation and its members, and the Uinta Formation overlying the Green River. A type stratigraphic section of the Green River and Uinta sections on the RD&D and preference right lease tracts is provided in Figure 3-4.

The base of the geologic section at this location is the Garden Gulch member of the Green River Formation. This member is a clay-rich oil-shale-bearing unit that consists of shales, thin sandstones and limestones, and oil shale beds and bedsets. The Garden Gulch at the RD&D lease tract includes two to three rich oil shale zones (zones R-0, R-1 and R-2) and two to three lean oil shale zones (zones L-1, L-2 and L-3). The Garden Gulch at the lease tract is approximately 200 ft thick.

The orange marker is a key correlative horizon within the lower portion of the Green River. It is generally recognized on resistivity logs through the unit, and it generally represents the base of rich oil shale development.



Source: Hood and Yurewicz, 2008

Figure 3-3: Cross Section from West to East Across the North Central Portion of the Piceance Basin, Illustrating Basin Asymmetry and Synclinal Structure. Shows Relative Position of Oil-shale-bearing Strata of the Green River Formation Relative to the Deeper Gas Bearing Mesaverde Group.

The main oil-shale-bearing unit of the Green River Formation is the Parachute Creek member. This member is approximately 1500 ft thick in the lease tract. It is composed primarily of organic rich dolostones with minor amounts of shale, sandstone, and, in the lower parts, evaporites.

The Parachute Creek member is divided into two zones in the vicinity of the RD&D lease tract based on the presence of a groundwater dissolution surface. The portion of the Parachute Creek member that lies below the dissolution surface is called the saline zone. This zone contains rich oil shales, lean dolostones and evaporite beds containing nahcolite and some halite. This zone lies below the base of the lower aquifer. Above this dissolution surface, evaporite minerals have been largely dissolved from the member, whereas below this surface, the nahcolite and halite beds, crystals, and mixtures with oil shale are undisturbed by groundwater activity. Nahcolite is much more common in the saline zone than is halite. Nahcolite is a crystalline form of sodium bicarbonate ($NaHCO_3$). The dissolution surface is not a stratigraphic surface. It has been defined by groundwater flow and may cross stratigraphic surfaces.

Nahcolite occurs within the oil shales of the saline zone as discrete beds of brown or white nahcolite, as non-bedded crystalline aggregates scattered through the oil shale, and as fine-grained crystals, mixed with oil shale (Dyni, 1974). Amounts in oil shale units are quite variable ranging from near 0% in extremely rich oil shale beds and bedsets to 30-50% by weight in some of the leaner oil shale layers. Some beds of nahcolite, for example the Boies Bed in Figure 3-4, are nearly pure nahcolite (> 70%).

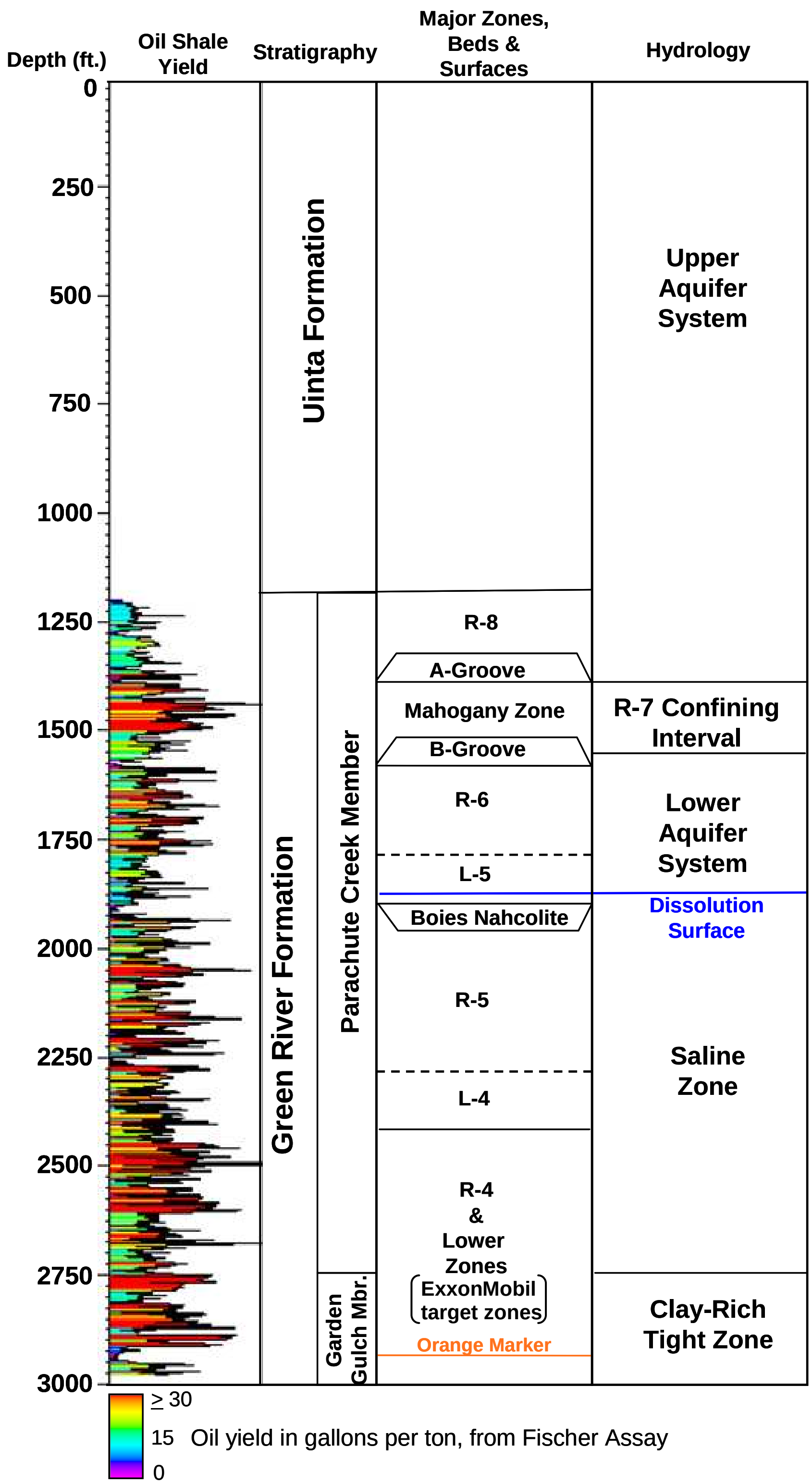


Figure 3-4. Stratigraphic Section for the RD&D Lease Tract Based Upon Stratigraphy and Aquifer Zones within the C0314 USGS Assay Well from Dyni (1998). This Well is within 1000 ft of North Border of Preference Right Lease Tract.

Rich oil shale zones within the saline zone at the RD&D lease tract include R-5, R-4, and R-3.

Above the dissolution surface, the Parachute Creek member consists of organically rich and lean oil shales, wherein nahcolite has dissolved and been removed. This removal results in dolostones that have layers with many vugs or open spaces within them. Where beds of nahcolite or halite were dissolved by groundwater, the dolostones may collapse to form breccias.

The R-6, R-7 (Mahogany Zone) and R-8 are rich oil shale intervals that generally lie above the dissolution surface. The Mahogany is bounded above and below by the A-Groove and the B-Groove. These units are lean dolostones, shales and siltstones.

The Uinta Formation is the rock unit at the surface in the RD&D and preference right lease tracts. This rock unit is composed of interbedded sandstone and shales. It is approximately 1,250 ft thick in the lease tract area. The lower portion of the Uinta Formation sandstones and shales are interbedded with the dolostones and shales of the upper portion of the Green River Formation.

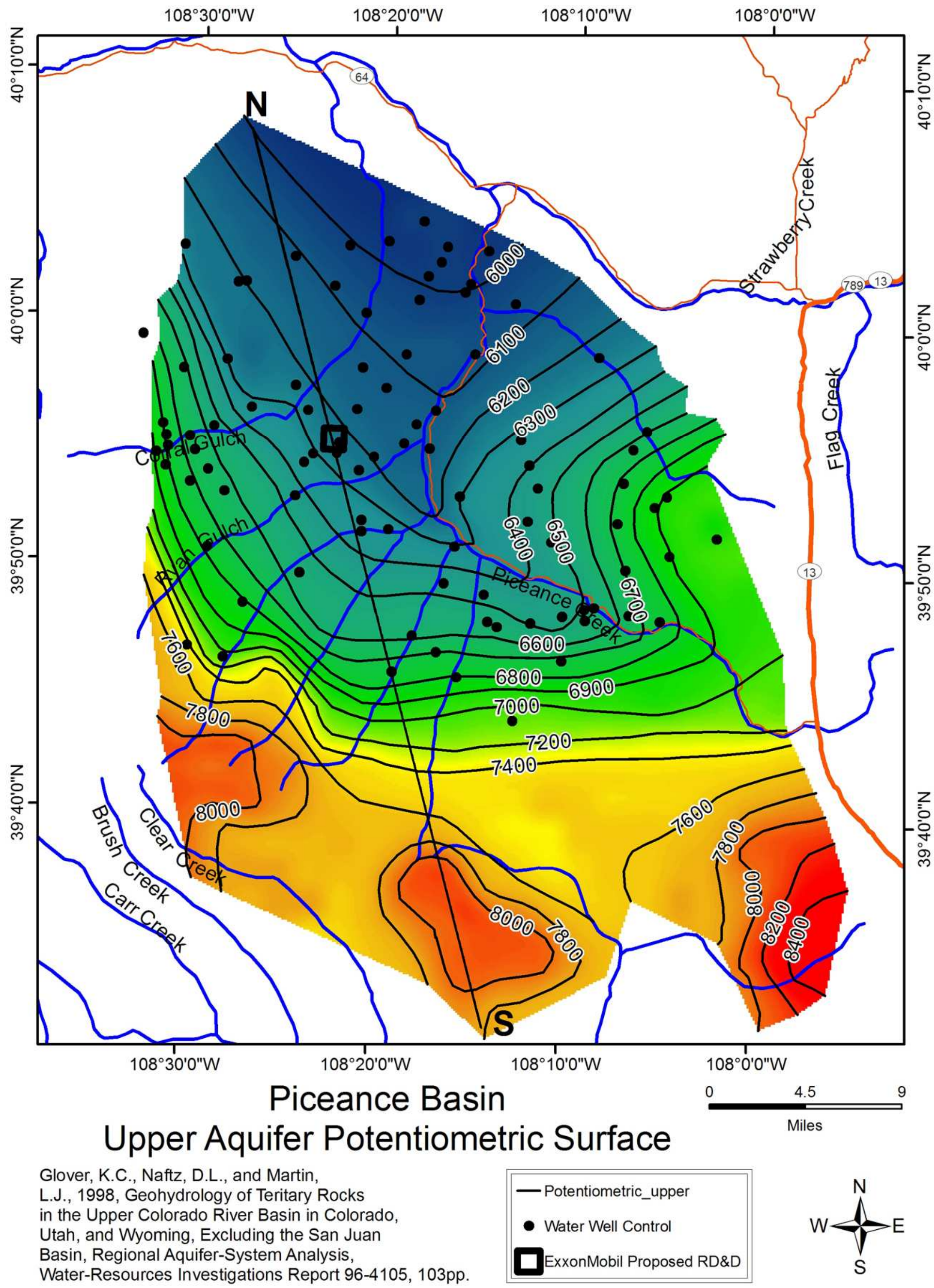
The strata in the vicinity of the lease area are horizontally bedded with dips of 10-20 degrees to the north, northeast. There is no significant structure on the lease tracts themselves. There is a significant normal fault system a mile or more to the southeast that has been mapped at the surface. This fault system strikes to the northwest and includes some displacement of the Green River Formation.

3.3 HYDROLOGY OF THE RD&D LEASE TRACT

3.3.1 SURFACE HYDROLOGY

This portion of the Piceance Basin receives approximately 12-20 inches of precipitation per year. Most of the precipitation is from snowmelt. Four intermittent stream beds are present on the preferential right lease tract. These fill with water in the March through May timeframe due to snowmelt in the area but are dry most of the rest of the year. Water flowing off the lease tract goes to Yellow Creek and then into the White River.

There are two major aquifer systems present on the lease tract area: the upper aquifer system, and the lower aquifer system (see Topper et al., 2003). As shown in Figure 3-4, the upper aquifer system consists of the Uinta Formation sandstones and the A-Groove aquifer just above the Mahogany Zone. The number of discrete aquifer subunits in the upper aquifer zone is not known at this time. The Uinta formation sandstones are known to be charged with water in other portions of the basin. The A-Groove is also known as an aquifer throughout the Piceance Basin. Connection between the Uinta sandstones and the A-Groove is via fracture transmission through the R-8 interval. The R-8 interval also serves as an aquiclude in this area according to work by Day, et al. (2010). The upper aquifer has hydraulic conductivities from less than 0.2 to greater than 1.6 ft/day (Topper, 2003). Water flow in the subsurface is dominantly to the northeast (Figure 3-5).



Source: Robson and Saulnier, 1981

Figure 3-5: Regional Potentiometric Surface for the Upper Aquifer

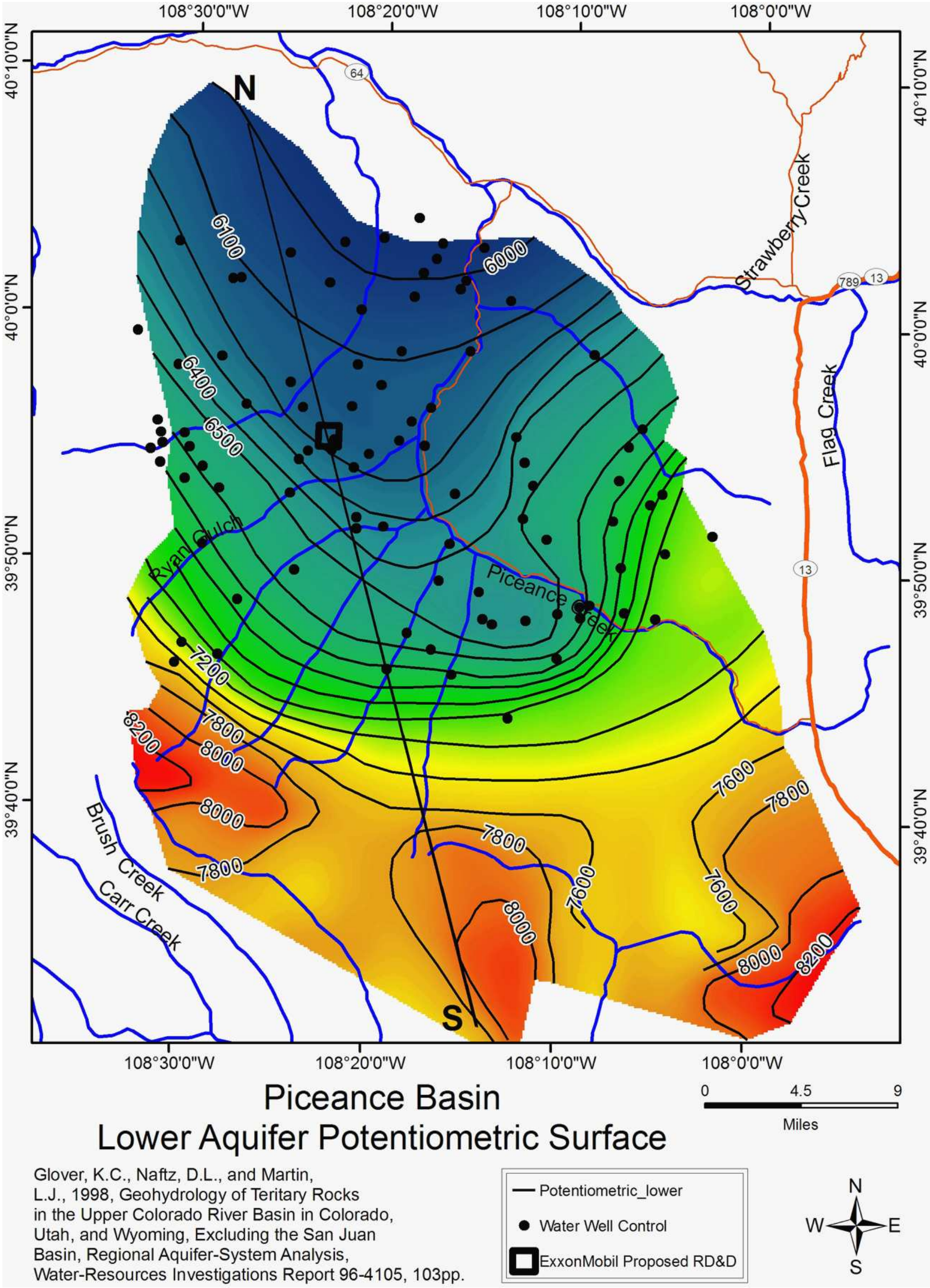
The upper and lower aquifer systems are separated by the R-7 or Mahogany confining interval. This interval consists of very organically rich oil shale that may exceed 50 ft in thickness. This rich oil shale is not as well fractured as leaner intervals, and water flow rates are thus lower. Horizontal hydraulic conductivities from the USGS (1982) range from 0.0003 to 0.1 ft/day. Vertical conductivities measured by the USGS (1982) are from 0.0001 to 0.03 ft/day.

The lower aquifer consists of the B-Groove aquifer and confined aquifers within the organically lean portions of the R-6 interval. Connection between confined aquifers is via fracture networks that span the rich intervals of the R-6. Hydraulic conductivities range from less than 0.1 ft/day to greater than 1.2 ft/day. Yields can be high with values up to 1000 gallons per minute recorded (Topper, 2003). Water flow is dominantly to the northeast (Figure 3-6).

The base of the lower aquifer is demarcated by the dissolution surface that, on the RD&D lease tract, is probably present within the basal portions of the L-5 interval. This surface is the present-day location of the dissolution of evaporite minerals from the dolomitic oil shales of the Parachute Creek. Below this surface water does not occur, as evidenced by the presence of the highly water-soluble evaporite minerals halite and nahcolite.

The clay-rich Garden Gulch member is present below the saline zone. Work by American Shale Oil (AMSO) several miles to the south, has confirmed that the Garden Gulch is not serving as an aquifer (Burnham 2010).

The actual number of distinct bedrock aquifers at any given location may be more complex than the two-aquifer system previously described. This is because rich oil shales are relatively impermeable and serve as aquitards that, in some locations, may subdivide the upper and lower aquifers into several hydrologically distinct units. Day et al. (2010) have described these various confined aquifers and the aquitard units within the northwest Piceance Basin.



Source: Robson and Saulnier, 1981

Figure 3-6: Regional Potentiometric Surface for the Lower Aquifer

3.3.2 GROUNDWATER QUALITY

The upper bedrock and alluvial aquifers are characterized by relatively fresh, sodium bicarbonate waters with low total dissolved solids (TDS <2,000 mg/L). Water quality in the alluvial aquifers is similar to that in the upper bedrock aquifer (Weeks et al., 1974).

The lower bedrock aquifer is more saline, with sodium bicarbonate waters and high chloride, fluoride, and TDS values of up to 40,000 mg/L (Weeks et al., 1974; Robson and Saulnier, 1981). Average TDS in the lower aquifer is much greater than the upper and alluvial aquifers as a result of the dissolution of minerals in the Parachute Creek member below the Mahogany zone. Additionally, Weeks et al. (1974) reported the presence of aluminum, arsenic, barium, boron, iron, lead, lithium, manganese, molybdenum, selenium, and strontium in the lower aquifer in at least trace amounts. The consistently high concentrations of elements such as barium, boron, and lithium in the northern part of the Piceance Basin were concluded to result from the dissolution of nahcolite and halite deposits.

3.4 ESTIMATE OF THE QUANTITY/QUALITY OF ALL MINERAL RESOURCES ALONG WITH PROPOSED CUTOFF GRADES

The resource interval of interest for oil shale development lies within the Green River Formation from the top of the Mahogany zone to the base of the R1 zone (orange marker; see Geology of the RD&D Lease Tract section). This interval is located at approximately 1,280 to 2,900 ft subsurface. Using oil shale assay data collected and published by the United States Geological Survey (Dyni, 1998), ExxonMobil has constructed a three-dimensional geological model of oil shale thickness and grade. Based on this model, the total Green River shale oil resource of the nominated RD&D lease is estimated to be 0.6 billion barrels of oil equivalent (GBOE) in place. The estimated shale oil resource in the proposed preference right lease area is 1.7 GBOE in place. Table 3-1 summarizes the important parameters for oil shale and other minerals within the proposed RD&D lease and preference right lease areas of Section 34.

Nahcolite and dawsonite resources are gross in-place estimates based on maps published by Beard et al. (1974) for dawsonite and on the data from Brownfield et al. (2009) for nahcolite.

Table 3-1 presents maximum values for the resources in the RD&D lease because no cutoff grades are included. For in situ methods, recoverable resource is a complex function of grade, thickness, and accessibility.

Table 3-1: Oil Shale Resource Parameters (Section 34)

Parameter	Value
Surface elevation	6,516 – 6,767 ft asl
Resource elevation	3,787 – 5,452 ft asl
Total Area (RD&D lease + preference right)	632.14 acres
Average overburden depth	1,280 ft (depth to top Mahogany)
Average thickness	1,620 ft
Estimated in-place resource	RD&D lease: 0.6 GBOE Preference right area: 1.7 GBOE Total: 2.3 GBOE
Nahcolite Resource (Brownfield et al., 2009)	RD&D lease: 87 million tons Preference right area: 253 million tons Total: 340 million tons
Dawsonite Resource (Beard et al., 1974)	RD&D lease: 30 million tons Preference right area: 88 million tons Total: 118 million tons

3.5 LOCATION AND DESIGN OF THE PROPOSED ROADS, WELL PADS, PONDS, POWERLINES, PITS, MONITORING WELLS, STORAGE TANKS, SURFACE STRUCTURES/FACILITIES, STACK PARAMETERS AND AIR EMISSIONS, TOTAL AREA OF DISTURBANCE

ExxonMobil's RD&D Lease nomination encompasses Lots 1, 2, 7, and 8 (northeast quarter), comprising ~155.82 acres of Section 34 of T1S, R98W, 6th P.M., Rio Blanco County, Colorado, United States of America.

The exact test and monitoring locations, and sizing of processing facilities, will be determined after further evaluation, including site-specific appraisal and environmental analysis. Figure 3-7 presents a notional RD&D layout on a satellite image of the proposed RD&D lease. In the configuration shown in Figure 3-7, ExxonMobil would request an exception to the 500-ft setback designated in the Oil Shale RD&D Lease form, as discussed during the January 19, 2011 meeting. ExxonMobil Operations Integrity Management Systems (OIMS) will be used throughout the life of the project to provide safe and proper operation of facilities to protect personnel and the environment.

Road construction needs will be moderate because a mature road network already exists in the area. Additional roads would be constructed to connect the RD&D acreage with nearby County Road 83. We estimate that a maximum of one to four miles of existing road upgrades and new roads will be needed within the proposed lease. Routing, construction, and reclamation of new roads will comply with BLM's "Surface Operating Standards for Oil and Gas Exploration and Development." New roads will follow existing tracks and trails where possible.

It is anticipated that the total surface disturbance will not exceed 50 acres at any given time, exclusive of roads, utilities, and gas pipeline right of ways. Site activity will be divided into different phases, as described in the schedule of operations that is presented in the "development sequence section".

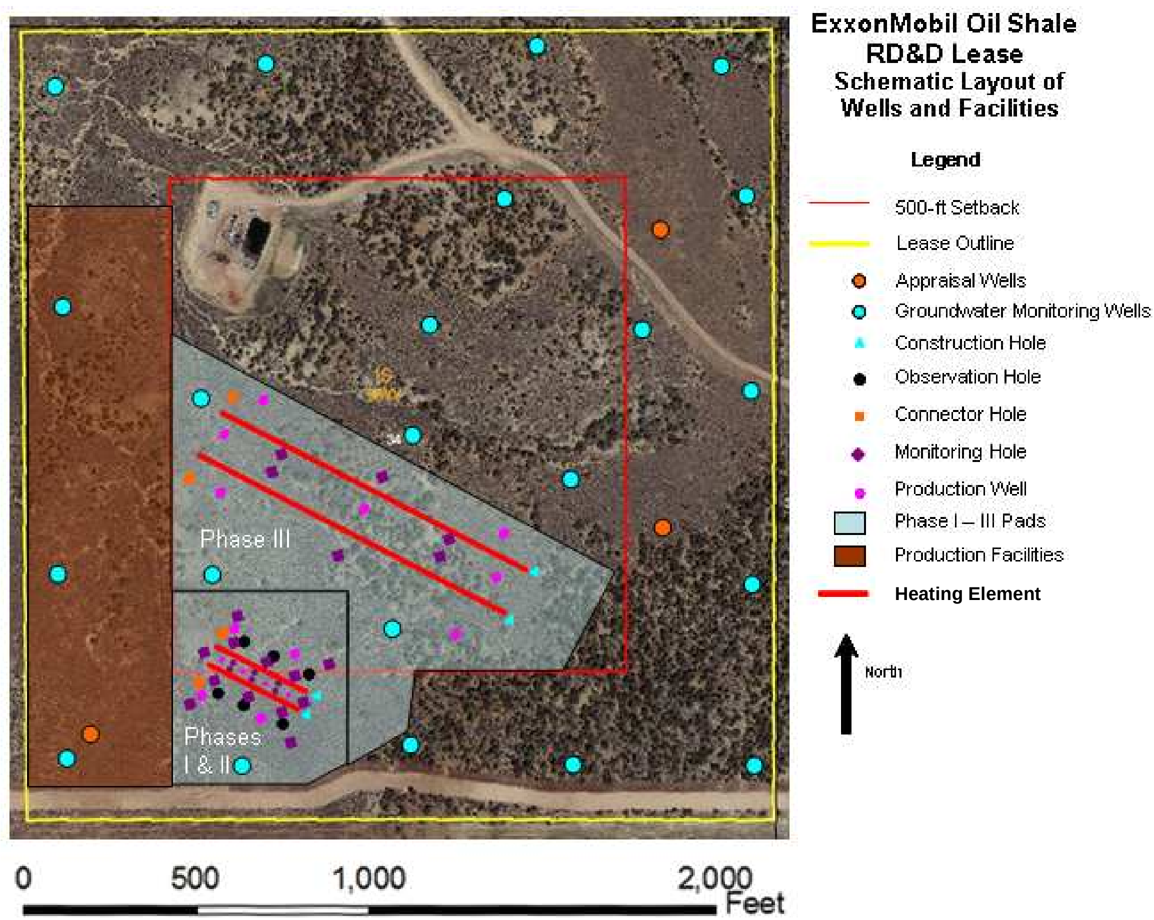


Figure 3-7: Notional Layout of Wells & Facilities on ExxonMobil's Proposed RD&D Lease

3.5.1 APPRAISAL

3.5.1.1 Appraisal and Groundwater Monitoring Wells

Initially, surface disturbance will occur with drilling appraisal and groundwater monitoring wells, roads, and other infrastructure (i.e., field office). The appraisal wells will be drilled from the surface to the base of the Green River Formation. Continuous coring will be done in each well from the top of the Parachute Creek member to the base of the Green River Formation. Wells will be wireline logged over their entire depth. The purpose of the appraisal wells is to provide local confirmation of locations of geologic markers and provide core for evaluating the richness and mineral composition of the oil shale.

It is anticipated that the appraisal and groundwater monitoring wellpads will be up to 1.0 acre in size, including mud pits. Small tests may be conducted in the appraisal wells and/or groundwater monitoring wells, to determine minimum in situ stress direction. The appraisal wells are planned to be abandoned or converted to groundwater monitoring wells. Wellpads around abandoned appraisal wells will be restored per the surface reclamation plan. Groundwater monitoring wellpads will be restored per the surface reclamation plan, leaving a 30-foot radius around each well for monitoring access, adjacent to an access road. The access road and small access wellpad will be maintained for each groundwater monitoring well to ensure access for periodic sampling and monitoring of groundwater, and maintenance, as needed. To support maintenance, the associated wellpad may be temporarily enlarged, but restored per the surface reclamation plan, leaving a 30-foot radius around each well for monitoring access, adjacent to an access road.

3.5.1.2 Buildings and Infrastructure/Utilities

Site buildings will include a temporary building or trailer for office space, and a warehouse or storage shed for equipment such as pipes, valves, fittings, and controls. A safety/security fence will surround the temporary building or the area of activity, as needed to protect livestock and wild game. Building(s) may be tied-in with the local electrical grid during Appraisal, pending discussion with White River Electric Association (WREA). Otherwise, electricity will be supplied from portable generators equipped with appropriate noise and emission controls. Water for all needs will be trucked to the site.

3.5.2 PHASE I

3.5.2.1 Buildings and Infrastructure/Utilities

Phase I site buildings and infrastructure/utilities will be handled in a similar fashion to that described in Section 3.5.1.2.

3.5.2.2 Drilling and Subsurface

Phase I drilling and subsurface work will focus on the construction of two successful planar heaters at depth. Successfully building an electrically conductive fracture in the zone of interest is critical to further research phases. The estimated size of the pad that will be used for both Phase I and II wells is 6 acres (exclusive of utilities right of way [Phase II], an access road, and pipeline to deliver produced fluids from the Phase I pad to the Production Facility), and will include accommodations for drilling (including mud pits), fracturing, and building electrical connections. It will also include several monitoring and direct observation holes to characterize the heaters. Additionally, small tests may be conducted in the Phase I wells and holes to determine minimum in situ stress direction.

- Estimated borehole count
  - Two in situ planar heater construction holes*
  - Two to four connection holes*
  - Six instrument monitoring holes*
  - Twelve to twenty-four observation holes*

* - Additional holes may be necessary, should initial attempts be unsuccessful at heater construction.

- Estimated equipment needed
  - Drilling equipment
  - Fracturing equipment
  - Portable generator(s)
  - Electrical-resistance measurement device

- Estimated supplies needed
  - Calcined coke or other nonhazardous fracture proppant
  - Graphite or other nonhazardous connection material
  - Cement
  - Casing
  - Water for drilling and completions operations

A proposed layout is shown in Figure 3-8.

3.5.3 PHASE II

Phase II will focus on installation of production and monitoring wells, tie-in of utilities and production headers and piping, erection of facilities required to analyze, process, store, and dispose of fluids produced from pyrolysis of oil shale kerogen.

Up to approximately 1.7 MW of electrical power from the nearby power grid will be delivered to each of the in situ heaters. This electrical power will resistively heat the formation. Production wells will be placed appropriately to collect hydrocarbons from between and from either side of the two heaters. This plan is expected to produce up to approximately 75-175 barrels of oil per day (BOPD), 50-350 thousand standard cubic feet per day (kscfd) of gas, and 40-80 barrels of water per day (BWPD). The heaters are planned to be energized for approximately 6 months. Production is expected to begin soon after the onset of heating and continue for some time after heating stops.

3.5.3.1 Utilities

Phase II construction will include bringing in electrical power from a WREA substation located off lease, as supply to the heaters built in Phase I (up to 2 each at up to approximately 1.7 MW), as well as for the production facilities and office and building space sited in the production facilities area. It is expected that we will be able to tie-in to the WREA power lines running along the southern boundary of the proposed RD&D lease. The power demands for the production facilities, office, and building space, will be determined at a later time, through detailed design of said facilities. It is possible that WREA may need to upgrade the lines leading to our tie-in, pending review of appraisal information and subsequent detailed design of our electrical power needs.

Although produced gas is expected to provide ample supply for onsite needs (fluid processing), additional may be trucked to site, or a small tie-in to the local natural gas pipeline infrastructure may be needed to supplement gas produced during Phase II pyrolysis, and for startup purposes.

3.5.3.2 Drilling and Subsurface

Phase II drilling and subsurface work will include installation of monitoring wells, production wells, and associated production header, with pipeline to transport the produced fluids to the production facility. In addition, equipment may be installed to provide artificial lift in production wells, along with production pumps/compressors, as needed to deliver produced fluids to the production facility. Electric motor-driven equipment will be considered, when feasible, for noise mitigation purposes. If engine-driven equipment is used, noise controls will be employed to maintain allowable noise limits at the lease boundary. The same pad prepared for Phase I drilling will be used to support Phase II drilling and subsurface construction, including mud pits.

Oil and gas produced by the in situ planar heaters will migrate to the production wells, where they will be collected and piped to the production facilities for testing, processing, or disposal. Figure 3-8 shows a generic layout of the construction holes, production wells, and monitoring holes.

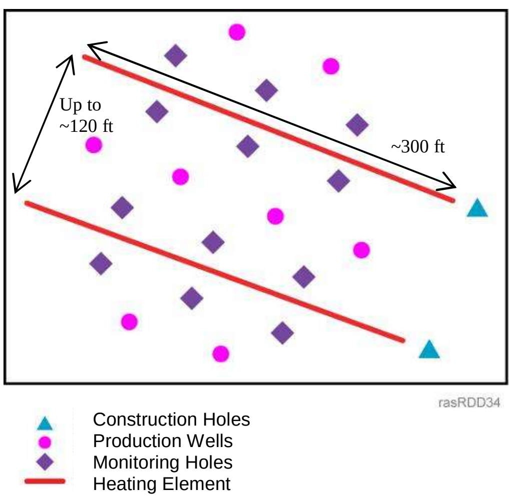


Figure 3-8: Surface Layout of Wells for Phase II Operations

- Estimated borehole/well count*
  - 12 production wells*
  - 12-24 observations holes*
  - 12 monitoring holes*

* - Additional wells and holes may be necessary, should initial attempts be unsuccessful at constructing the heater.

- Estimated equipment needed
  - Drill rig and associated equipment (including portable generators, as needed)
  - Fracturing equipment

- Estimated supplies needed
  - Casing, tubing, cement, and wellheads
  - Up to 3.4 MW electrical power for *in situ* heating
  - Thermocouples
  - Downhole voltage and amperage sensors
- Water for drilling and completions operations (trucked in)

3.5.3.3 Produced Fluids Processing

Production facilities and infrastructure to support storage, processing, and disposition of produced fluids will be appropriately sized and erected onsite during this and subsequent phases, to accommodate the expected fluid production rates during each respective Phase of operation. The production facilities are notionally described at the end of this section. Although the Phase II and Phase III produced fluids are expected to have similar compositions, the different stream volumes may require different equipment size and types to achieve the required processing. Electric motor-driven equipment will be considered, when feasible, for noise mitigation purposes. If engine-driven equipment is used, noise controls will be employed to maintain allowable noise limits at the lease boundary.

3.5.4 PHASE III

Phase III will consist of a pilot of in situ planar heater technology at depth. The pilot will consist of two heaters, successfully constructed at or near the anticipated size and spacing required for commercial development. The goal of this phase is to collect the information necessary to determine the overall commerciality of the in situ process: hydrocarbon recovery, sodium mineral recovery, environmental acceptability, and economic viability. Figure 3-9 shows a proposed layout of the wells. The actual number of each type of wells and holes, will be determined after completion of Phase II work. It is anticipated that the number of wells and holes could be greater than those used in Phase II, corresponding to the larger heater size. Additionally, small tests may be conducted in the Phase III wells and holes to determine minimum in situ stress direction. The site of the Phase III heaters will likely be located near the site used in Phases I and II.

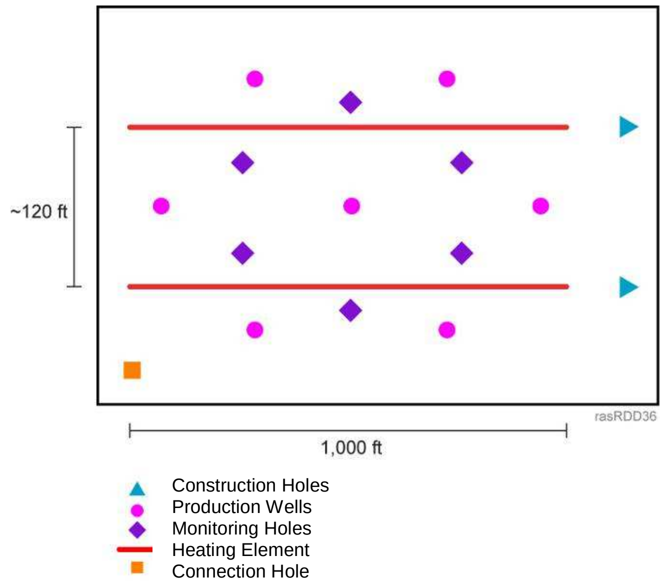


Figure 3-9: Surface Layout of Wells for Phase III Operations

Up to approximately 4 MW of electrical power from the nearby power grid will be delivered to each of the two heaters to resistively heat the formation. Production wells will be placed appropriately to collect hydrocarbons from between and around the heaters. This operation is expected to produce peak rates of approximately 400 to 700 BOPD, 350 thousand (kscfd) to 6 million standard cubic feet per day (Mscfd) of gas, and 200 to 300 BWPD. The heaters will be operated for approximately 5 years. Shorter or longer operation times may be used, depending on the size and spacing of the heaters. Production will begin soon after the onset of heating and will continue for some time after heating stops. If suitable for sale, gas will be processed and distributed through nearby sales gas pipelines. The oil will be collected, some will be used for processing research, and the remainder will be trucked for sale or disposal. The quantity of oil available for potential sale from Phase III operations is not expected to be sufficient to support a commercial operation.

<u>Utilities</u>

Phase III may include upgrading Phase II power lines from the WREA substation or laying additional lines, depending on the capacity of the Phase II power lines. Adequate capacity is required to supply electricity to each of two heaters (~ 4 MW each), production facilities, and office and building space sited in the production facilities area. Power demands will be determined at a later time, through detailed design.

3.5.4.1 Drilling and Subsurface

Phase III drilling and subsurface work will focus on the construction of two pilot planar heaters at depth, and include installation of similar types of holes and wells used in Phase I and II. The estimated size of the pad supporting Phase III wells is ~20 acres (exclusive of utilities right of way, an access road, and pipeline to deliver produced fluids from the

Phase III pad to the Production Facility), and will include accommodations for drilling (including mud pits), fracturing, and building electrical connections. It will also include several instrument monitoring and direct observation holes to characterize the in situ heater. Produced fluids from production wells are expected to be gathered in production lines, and delivered to the production facility through onsite piping. In addition, equipment may be installed to provide artificial lift in production wells, along with production pumps/compressors, as needed to deliver produced fluids to the production facility. Electric motor-driven equipment will be considered, when feasible, for noise mitigation purposes. If engine-driven equipment is used, noise controls will be employed to maintain allowable noise limits at the lease boundary.

3.5.4.2 Produced Fluids Processing

Produced fluids processing during Phase III will be approached in a fashion described previously in Section 3.5.3.3.

3.5.4.3 Production Facilities

This section describes the generic facilities needed for processing produced fluids. Pending detailed design, specific process units may be substituted/absent at the very small rates expected during Phase II operations. The facilities design will be finalized after the site-specific environmental analysis and in accordance with all permits for the RD&D lease.

The produced stream will be a mixture consisting of gas, oil, water, and some impurities (e.g., H_2S and CO_2). The stream components will be separated and treated for the removal of impurities using typical oil and gas industry processes and facilities. A conceptual process block flow diagram is shown in Figure 3-10.

When the produced stream reaches the surface, a three-phase separator will separate it into three streams (gas, liquid hydrocarbon, and water). The gas and water leaving the separator will be ‘sour’ streams because of the presence of sulfur compounds and CO_2. As explained in the following paragraphs, the gas, liquid hydrocarbon, and water will be processed and treated to reduce impurities to meet the appropriate environmental standards and regulations.

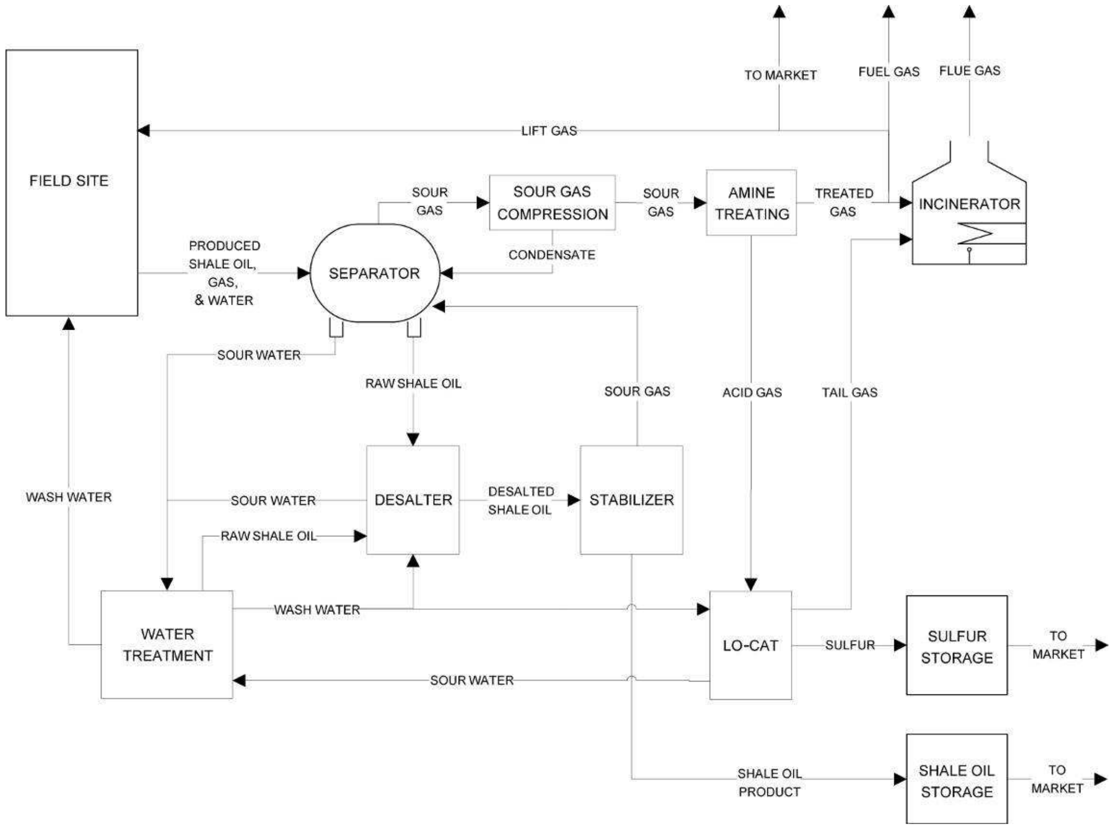


Figure 3-10: Oil Shale Production Facilities

3.5.4.4 Gas Processing

After initial separation, the sour gas will be compressed and cooled to condense out any remaining sour water and/or liquid hydrocarbon. The condensed liquids will be routed appropriately for further handling. Once compressed and cooled, the sour gas may be sent to an amine treating unit, which would include an absorber column and a stripper column.

In the absorber column, the gas would be contacted with an aqueous solution of methyl diethanolamine (MDEA), or other selective solvent, which would absorb H_2S, other sulfur compounds, CO_2, and other acids. The absorption is selective in that it removes a very high fraction of the sulfur compounds but only a portion of the CO_2. A large portion of the resulting clean gas would be used for process fuel and other purposes, such as well injection lift gas, as needed. If sufficient quantities of clean gas are available, the gas may be sent to market. The most likely destination for gas from this facility would be one of the gas processing plants that serve the Piceance Basin. If sales are not practical, gas could be burned in a properly permitted incinerator designed to minimize emissions of CO and NOx.

In the stripper column, the MDEA would be continually regenerated for reuse. Regeneration involves removing sulfur and other compounds from the MDEA solution. This process creates an acid gas stream containing H_2S and CO_2. The acid gas would be sent to a Lo-Cat unit where the H_2S would be converted to elemental sulfur. The tail gas from the Lo-Cat unit would be incinerated. The Lo-Cat process yields a relatively small water stream. Ammonia (NH_3) in the gas will have no detrimental effect on the Lo-Cat process and would end up as ammonium compounds in the water stream, which would be treated as discussed in the following section. The small amount of residual NH_3 in the tail gas would not significantly contribute to NOx emissions from the gas incinerator. The Lo-Cat process makes a high quality sulfur product that should be marketable. Elemental sulfur generated through the Lo-Cat process would be temporarily stored onsite in appropriate vessels prior to shipping offsite for disposal or sale. Skid-mounted amine units and Lo-Cat units are commercially available in the required size.

Alternate gas processing may be necessary pending appraisal findings that could affect process design. This could include scrubbing of gases prior to incineration, after incineration or a combination of both.

3.5.4.5 Liquid Hydrocarbons

The liquid hydrocarbon may contain significant concentrations of salts and may, therefore, be desalted after leaving the separator. In the desalter unit, recycled wash water would be added to the liquid hydrocarbon to dissolve the salt. The saltwater and hydrocarbon streams would then be separated and routed appropriately. The salt water would be treated or appropriately disposed, and the liquid hydrocarbon will be sent to a stabilizer unit where it will be conditioned for storage and transport.

Stabilization involves removing light components to reduce the vapor pressure of the oil for convenient and safe storage and shipment. In the stabilizer unit, the oil will be distilled into light (gas) and heavy (oil) fractions. The gas will be injected into the inlet of the three-phase separation unit for further processing, and the oil will be sent to appropriate storage vessels.

The facilities will include an array of safety systems typical of ExxonMobil production facilities. This includes an overpressure protection system, with pressure relief devices that vent through a piping system that terminates at a lighted flare. The flare system will only be used for emergency pressure relief. The flare will be designed during the detailed design of production facilities.

Alternate liquid hydrocarbons processing may be necessary pending appraisal findings that could affect process design.

3.5.4.6 Produced Water

The sour water streams from the three-phase separator and the Lo-Cat unit may be treated for reuse or disposal. The water treatment facility will remove H_2S from the sour water and may include equipment for recovering sodium minerals from produced water. Any remnant oil recovered by the water treatment facility may be sent to the desalter for further treating. Sour gas recovered from the water treatment facility would be sent to the Lo-Cat unit for removal of sulfur compounds.

Alternate produced water processing may be necessary pending appraisal findings that could affect process design.

3.6 ACCESS REQUIRED FOR ELECTRICAL POWER, NATURAL GAS, WATER AND COMMUNICATIONS

Right-of-way access includes local road Route 83, which cuts across the southern half of Section 34 within the preference right lease area. Furthermore, utility corridors lie to the south and west of the proposed tract.

Temporary overhead power lines and associated right-of-way will be required to bring electrical power from the nearest commercial power-supply location available at the time of startup.

Additional natural gas is not expected to be required. However, upon detailed design, if supplemental natural gas is required, it may be trucked to site, or a right of way may be required to tie in to local gas gathering and distribution lines to supply gas to the site.

It is expected that fresh water for drilling, dust control, and other needs will be trucked to site and stored in tanks located in a bermed area. Fresh water tanks are not expected to require lined storage.

Communications will be by satellite or by microwave connections with ExxonMobil's ongoing Piceance operations.

3.7 EQUIPMENT LIST, DEVELOPMENT SEQUENCE, ESTIMATED PRODUCTION RATE, AND ESTIMATED RESOURCE RECOVERY FACTORS

Table 3-3 provides the notional processing equipment list associated with ExxonMobil's proposed Oil Shale RD&D lease development. A more detailed equipment list will be made upon completion of detailed engineering.

*Table 3-3: Oil Shale Production Facilities Equipment List**

Equipment Type	Purpose
Portable generators	Small electrical power needs prior to tie-in to local power grid
Three-phase separator	Oil, gas, and water stream separation
Compression system	Sour gas compression
Amine treating skid unit	H_2S absorption and MDEA regeneration
Gas incinerator	Combust treated and tail gas while controlling CO and NOx emissions
Desalter	Separate salt from shale oil
Stabilizer	Stabilize shale oil for storage and transport
Lo-Cat skid unit	Convert H_2S in acid gas into elemental sulfur
Water treatment facility	Purify sour water streams and recover minerals
Produced water storage vessels	Proper temporary storage of produced water
Sulfur storage vessels	Proper storage of sulfur
Shale oil storage vessels	Proper storage of shale oil

* Equipment list may change pending appraisal findings and any associated process design changes

The Schedule of Operations Plan includes four or five stages of research and development, as outlined in Figure 3-11 and Table 3-4. Progress to each successive stage depends upon successful completion of the prior stage. Activities on the research, development, and demonstration (RD&D) lease will be year-round and continuous to facilitate the work required to target a commerciality decision by the end of the initial ten-year lease term. Unforeseen results may lead to a second pilot that would require an extension of the lease for up to five additional years.

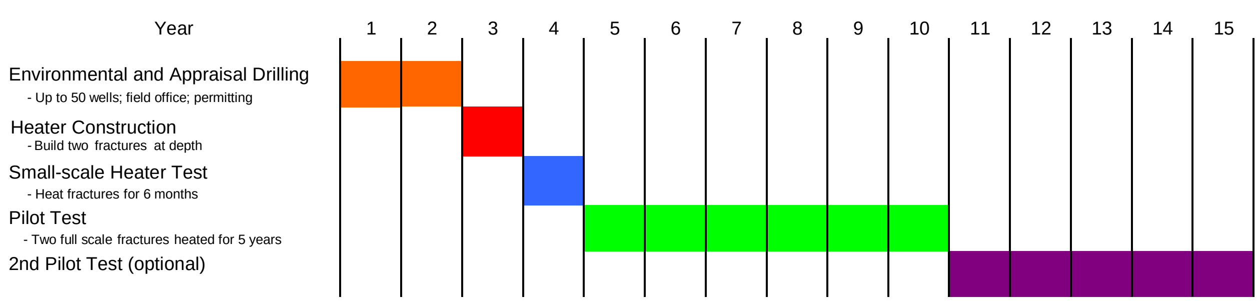


Figure 3-11: Schematic of the Operations Timeline

Table 3-4: Schedule of Operations

Time	Operations
Years 1 – 2	**Design and permit operations on RD&D lease** ♦ Design and build infrastructure (roads, field office). ♦ Drill ~3 appraisal wells to determine location for future experiments. ♦ Drill up to 48 groundwater-monitoring wells to obtain baseline data. ♦ Apply for reclamation and other permits and approvals.
Year 3	**Phase I: Heater construction at depth (small scale)** ♦ Extend Colony experience to construct an in situ planar heater in the target zones. ♦ Construct two or more small heaters at depth. – Verify electrical continuity of heaters. – Construct electrical connections to the heaters. – Evaluate characteristics and confinement to target zone. ♦ Phase I will comprise two or more construction holes, electrical connection holes, monitoring holes, and 12 -24 observation holes. ♦ Because there is no plan for heating, no oil or gas will be produced.
Year 4	**Phase II: Heater operation at depth (small scale)** ♦ Electrify up to 2 existing planar heaters from Phase I to heat oil shale to pyrolysis temperature and produce oil and gas. – Verify effectiveness and reliability of the heaters to heat oil shale to conversion temperature. – Assess fluid properties of shale oil and gas produced from the conversion process at depth. – Assess groundwater protection measures. ♦ Phase II will require ~12 production wells and ~12 additional monitoring holes. ♦ Phase II will require up to ~3.4MW of electrical power to be delivered *in situ* from the power grid. ♦ Heating will last for ~6 months with production following soon after the onset of heating. Small volumes, up to approximately 75-175 BOPD, 40-80 BWPD, and 50-350 kscfd are expected to be produced. Potential sale of these hydrocarbons is not expected to be sufficient to support a commercial operation.

Time	Operations
Years 5 – 10	**Phase III: Pilot scale testing of the in situ technology** ♦ Demonstrate applicability of in situ planar heater on a field scale. ♦ This pilot will comprise two heaters, one connector well, ~12 production and monitoring wells, and 12-24 observation holes. ♦ The pilot is estimated to require up to ~7 MW of electric power to be delivered *in situ*. ♦ Heat the formation for 2 to 5 years. Production will begin within the first year of heat onset. ♦ Peak produced volumes are estimated to be up to 400 – 700 BOPD, 350 kscfd – 6 Mscfd of gas, and 200 – 300 BWPD. Potential sale of these hydrocarbons is not expected to be sufficient to support a commercial operation. ♦ After completion of the oil- and gas-production phase of the pilot test, the ground may be flushed with water to test recovery of the sodium minerals. Groundwater remediation is not expected to be required. However, if necessary, as indicated by groundwater monitoring results, water could be used to flush and mitigate groundwater contamination using production wells as injection and recovery wells. This procedure could extend beyond Year 10. ♦ Upon successful completion of the pilot, ExxonMobil will seek to convert the RD&D lease to a commercial lease. (If the lease is not converted, the site will be properly abandoned and reclaimed.)

Resource recovery factors are not well known at this time. This information is a primary objective of the RD&D lease work program

3.8 NUMBER AND LOCATION OF EMPLOYEES DURING CONSTRUCTION/OPERATIONS, TIMES/DATES OF CONSTRUCTION/OPERATIONS, INCLUDING THE AMOUNT/TYPE OF TRAFFIC REQUIRED FOR CONSTRUCTION/OPERATIONS, INCLUDING EMPLOYEE TRANSPORTATION

During construction of wells and facilities, peak loading may be 120 craft and labor employees and contractors. The construction phase will involve a maximum of 30 vehicles per day going to and from the site (10 commercial trucks and 20 passenger vehicles). Employee transportation will be by private vehicles.

During ongoing operations, total staff may be as large as 20 employees and contractors, estimated to make approximately five to ten round trips per day in total. These workers will likely be housed in hotels (if nonresidents) or in typical residential housing (if residents of the Western Slope) in Rifle, Meeker, Rangely, Silt, Parachute, or Grand Junction, CO.

See Table 3-4 for timing.

3.9 METHODS OF CONTAINMENT/DISPOSAL OF TRASH/WASTE MATERIAL PRODUCED

Small quantities of solid wastes will be generated throughout the life of the project. These wastes include construction wastes, garbage, and other miscellaneous solid wastes. Solid wastes will be sorted in appropriate trash containers for offsite disposal in accordance with applicable regulations.

Hazardous waste or other wastes, such as used oils, lubricants, hydraulic fluids, paints, and chemical reagents will be disposed offsite in accordance with applicable regulations.

Sanitary waste streams will be sent offsite for disposal in accordance with applicable regulations.

Drill cuttings that comprise soil and rock will be dewatered on site. Depending on the results of its toxicity characteristics (as determined by the Toxicity Characteristic Leaching Procedure [TCLP]), the dewatered cuttings may either be buried below grade if nonhazardous, or disposed offsite in accordance with applicable regulation. When buried below grade, the affected area will be revegetated in accordance with applicable regulations during the reclamation phase. Wastewater separated from the drill cuttings may contain constituents of concern, such as oil and grease, and suspended and dissolved solids. This wastewater may be treated for reuse or disposal; small quantities may be sent for offsite handling and processing.

3.10 LOCATIONS OF EXISTING/ABANDONED MINES, MONITORING, SOLUTION MINING, CORE, WATER, OIL AND GAS WELLS WITHIN ONE MILE RADIUS

There is a Williams gas well located in the northwest portion of the RD&D lease nomination. A topo/aerial map indicating all mines and wells located within a one mile radius, is provided in Attachment A - entitled Aerial Map (Sheet 1 & Sheet 2) and Attributes.

3.11 TYPICAL OIL SHALE STRUCTURE AND OVERBURDEN CROSS SECTIONS

The oil shale stratigraphy, the sequence of depositional units within the Green River Formation and the overall structural setting of the Piceance Basin are described in an earlier section entitled: “Geology of the RD&D Lease Tract”. In general, the oil shale units have modest dip to the ENE of about 10-20 degrees. Significant faulting has not been mapped at the surface within the RD&D or preference right lease tract areas.

4 THE FOLLOWING INFORMATION SHALL BE INCLUDED AS PART OF THE DRILLING PLAN, BUT SHALL BE MADE MORE SPECIFIC TO EACH WELL IF THE PLAN COVERS MORE THAN ONE WELL

4.1 ESTIMATED TOPS OF IMPORTANT GEOLOGIC MARKERS

Important geologic markers are listed below with approximate depths based on the stratigraphic section in Figure 3-4.

- Top Uinta Formation – 10 ft
- Top Parachute Creek Member – 1200 ft
- A-Groove – 1380 ft
- B-Groove – 1575 ft
- Dissolution Surface – 1875 ft
- Boies Nahcolite Bed – 1900 ft
- Top R-4 – 2425 ft
- Top Garden Gulch Member – 2730 ft
- Orange Marker – 2940 ft

4.2 ESTIMATED DEPTHS AT WHICH THE TOP/BOTTOM OF ANTICIPATED WATER, OIL SHALE, OIL, GAS, NAHCOLITE, OR OTHER MINERAL-BEARING FORMATIONS ARE EXPECTED TO BE ENCOUNTERED

Water, oil shale, nahcolite, dawsonite and halite are expected to occur within the RD&D lease tract. Water may be found from within 100 ft of the surface to the dissolution surface at approximately 1875 ft. Water may occur in this zone within discrete aquifers such as the A-Groove, B-Groove and within the organically leaner portions of the Parachute Creek member.

Oil shale is expected to be present from 1200 ft to 2940 ft within the Parachute Creek and Garden Gulch members of the Green River Formation. Oil shale will vary in terms of oil yield within this thickness.

Nahcolite, dawsonite and halite are anticipated to be present within the Parachute Creek member below the dissolution surface, from 1875 ft to 2730 ft. Nahcolite is the dominant evaporite present in the lease tract.

Oil and gas are not expected to be encountered to a depth of greater than 3000 ft on the RD&D lease tract. The Piceance Basin is generally not an oil productive basin. Gas resources are located within the Mesaverde Group and the Wasatch Formation below the Green River Formation. We do not anticipate any drilling to depths within or through the Wasatch Formation except for potential salt water disposal wells, which could utilize the Wasatch. See Figure 3-3 for positions and thickness of these units.

4.3 DESCRIPTION OF FORMATIONS TO BE DEVELOPED/HEATED ALONG WITH ASSOCIATED TEMPERATURES OF HEATING TECHNOLOGIES

ExxonMobil plans to perform heating experiments in the R-4 to Orange Marker portion of the geologic section, from approximately 2425 ft to 2940 ft. This includes the lower part of the Parachute Creek Member and the Garden Gulch Member of the Green River Formation. ExxonMobil's targeted heating zone was chosen to contain the process affected zone in a low-permeability envelope of unheated oil shale to protect proximate groundwater (and by extension, the surface water streams in communication with groundwater).

The R-4 and deeper section of the Parachute Creek Member is composed of a mixture of organic rich dolostone mixed with variable amounts of nahcolite, dawsonite and halite. Minor amounts of clay and sandy layers may be present. The halite and nahcolite can occur within the unit as dispersed crystalline masses of various sizes within the oil shales or as relatively pure layers of halite or nahcolite ranging from a few inches to several feet thick. These layers normally have some oil shale contained within them (Dyni, 1974). Dawsonite generally occurs as microcrystals within the oil shale units (Beard et al., 1974).

The Garden Gulch is predominantly a clay mudstone enriched in organic material to form oil shale. Nahcolite, halite and dawsonite are rare in this interval. Beds of sandy, silty and carbonaceous mudstone are present, mixed with the oil shales in varying amounts. Some limestones and dolomites, some organically rich, are also present. There is no groundwater aquifer within this zone.

Utilizing this in situ method, the bulk of the oil shale in the target interval will be heated to temperatures ranging from 300 to 375°C. Temperatures directly adjacent to the heater may reach 800 to 1,000°C.

4.4 DESCRIPTION OF PROPOSED CIRCULATING MEDIUM(S) TO BE USED IN HEATING OIL SHALE FORMATIONS

4.4.1 IN SITU PLANAR HEATER

Our leading oil shale technology, the proprietary in situ planar heater, is an energy-efficient method of converting oil shale to producible oil and gas. The process is designed to heat oil shale *in situ* by building a hydraulic fracture (a conventional oilfield technology) in the oil shale and filling the fracture with an electrically conductive material. Electricity is conducted from one end of the fracture to the other, making it a resistive heating element. Heat flows from the fracture into the oil shale formation, gradually converting the solid organic matter of the oil shale into oil and gas. The oil and gas are produced by conventional methods, as per Figure 4-1.

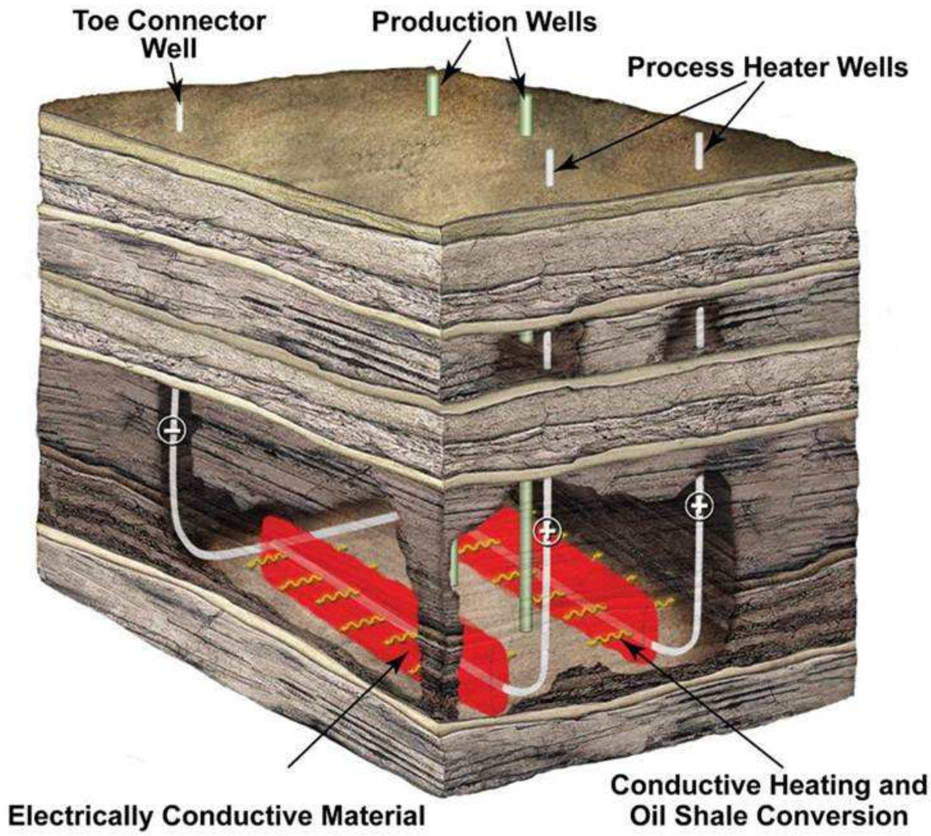


Figure 4-1: Schematic of ExxonMobil's in Situ Oil Shale Process

During heating and production of hydrocarbon fluids, no circulating fluid is expected to be used. However, upon conclusion of heating and production of hydrocarbons, ExxonMobil's patented technology to recover sodium-bearing minerals, will be tested. As cooling continues into Phase IV, some production wells may be converted to water injection wells. Water would be injected into the fracture network. This water would be heated upon entry into the hot oil shale and dissolve the sodium-bearing minerals; the water would be produced and the sodium-bearing minerals recovered. Recovered natrite could then be converted to sodium bicarbonate, as needed, with the addition of carbon dioxide. This process is described in more detail by Kaminsky et al. (2007).

4.5 TYPE/CHARACTERISTICS OF THE PROPOSED CIRCULATION MEDIUM TO BE EMPLOYED IN DRILLING, INCLUDING TYPES OF MUD AND WEIGHTING MATERIAL TO BE MAINTAINED

Drilling fluids will include compressed air and/or fresh water. Approved non-contaminating additives (e.g., bentonite, cellulosic polymer and/or biodegradable surfactants) will be used to enhance drill cuttings carrying properties. If areas are encountered while drilling that are prone to lost circulation, bridging materials such as calcium carbonate, nutshells, and/or fibers may be added to the drilling fluid. Minimal use of weighting material is anticipated, which may include calcium carbonate or sodium bicarbonate.

4.6 DETAILED DESCRIPTION OF FRACTURING METHODS, AND TYPES/AMOUNTS OF PROPELLANTS USED

The heaters are built by fracturing the construction holes and filling the fractures with a nonhazardous electrically conductive material, such as a mixture of calcined coke and cement. The horizontal section of the construction holes will be cased with electrically nonconductive pipe (likely fiberglass tubulars designed for downhole use), 5.5-in. in diameter. In Phase I, approximately 150,000 lb of calcined coke and 60,000 lbs of Portland cement will be pumped into the formation for each heater. In Phase III, approximately 1,000,000 lbs calcined coke and 400,000 lbs of Portland cement will be pumped into the formation for each heater. While detailed procedures will be developed as part of the early field work, the following generic procedure is representative of the expected procedure.

A generic procedure is provided for planned construction of the pilot scale planar heater. For the small scale test (Phases I and II), we envision a similar process, but involving a single stage fracturing process (no repeats in Step 9).

<u>Generic procedure for ~1000-ft horizontal well: Class ll, 5000 psi wellhead equipment, 5.5-in K-55 17 lb/ft casing to surface</u>

1. Check integrity of the casing by pressure testing casing
2. Move frac tanks
3. Use wireline / tractor services for depth control and perforation control
4. Run in the hole with removable bridge plug (RBP) and place at the toe using coiled tubing (CT) unit
5. Perforate first zone
6. Install 5000 psi frac stack on wellhead
7. Pump frac treatment with calcined petroleum coke, Portland cement and water
8. Run in hole with CT, clean out proppant, and move RBP to new location and perforate next zone
9. Repeat steps 5-8 for the subsequent zones
10. Clean well with CT and remove RBP
11. Shut-main valve and remove frac stack

Construction holes are expected to be drilled and completed in five to ten days. Projected equipment requirements include the typical oilfield pumps, tanks, and slurry-mixing equipment necessary for fracturing operations.

4.7 EXPECTED BOTTOM HOLE PRESSURES AND SPECIFICATION FOR PRESSURE CONTROL EQUIPMENT

4.7.1 PRESSURES

During drilling, we anticipate the formation will be normally pressured (0.433 psi/ft). At 3000 ft TVD, we expect a formation pore pressure of approximately 1,300 psi. Blow out preventer stacks and/or rotating control head specifications will meet ExxonMobil and agency requirements.

Pumping pressures during the fracture jobs are expected to be controlled by the horizontal *in situ* stresses in the formation. Once heating and kerogen conversion commence, pressures may reach the lithostatic gradient of about 1.0 psi/ft (3000 psi for 3000 ft depth).

During fracture treatment:

- Bottom hole pressure = 0.95 psi/ft gradient x 2900 ft = 2755 psi
- Hydrostatic during pad and flush ~ 1270 psi
- Expected treating surface pressure ~ 2755 + 1000 (friction) - 1270 = ~2500 psi

4.7.2 EQUIPMENT

- Wellhead equipment: wellhead with two side wing valves and Class ll 5000 psi rating.
- Production casing design will allow for heat expansion effects up to 500°F using 5.5-in K-55 17 lb/ft , bursting pressure = 5320 psi.
- Packers will be thermal packers that allow for expansion in heat application.
- Cement will be selected to have thermal properties that prevent its cracking.

When drilling from the surface down to zone of interest, we anticipate the formations will be normally pressured (increasing at 0.433 psi/ft). At 3000 ft TVD, we expect formation pore pressure of approximately 1,300 psi. The maximum overburden pressure at this depth (assuming 1 psi/ft) is 3,000 psi. Blow out preventer stacks and/or rotating control head specifications will meet ExxonMobil and agency requirements.

4.8 IDENTIFICATION OF WELLS USED FOR INJECTION AND/OR PRODUCTION ALONG WITH PROPOSED CASING SPECIFICATIONS ALONG WITH PROPOSED WELL LIFE

Schematic well locations are shown in Figure 3-7 for Phases I-III. We anticipate using 5.5-in K-55 17 lb/ft (5320 psi burst pressure) casing in the construction/heater wells and production wells. Four construction/heater wells, 14 production wells, and one produced water injection well (if needed) are planned. Heater well life is planned for five years, producer and injector well lives are planned for ten years.

A representative well sketch for construction/heater, production and injection wells is shown in Figure 4-2. We anticipate drilling and setting surface casing. This casing will be cemented back to surface level. Depending on the intended use of the well (heater, producer, injector, etc.), the well may be drilled with directional control to the target of interest. Producer/injector wells are anticipated to be vertical while the construction/heater wells are anticipated to have a horizontal interval of ~1,000 feet. In all cases, we anticipate running the inner casing string to the total drilled depth of the well and cementing this string back to surface level. Producer wells may require some form of artificial lift, in which case a tubing string may be used to convey produced fluids back to the surface.

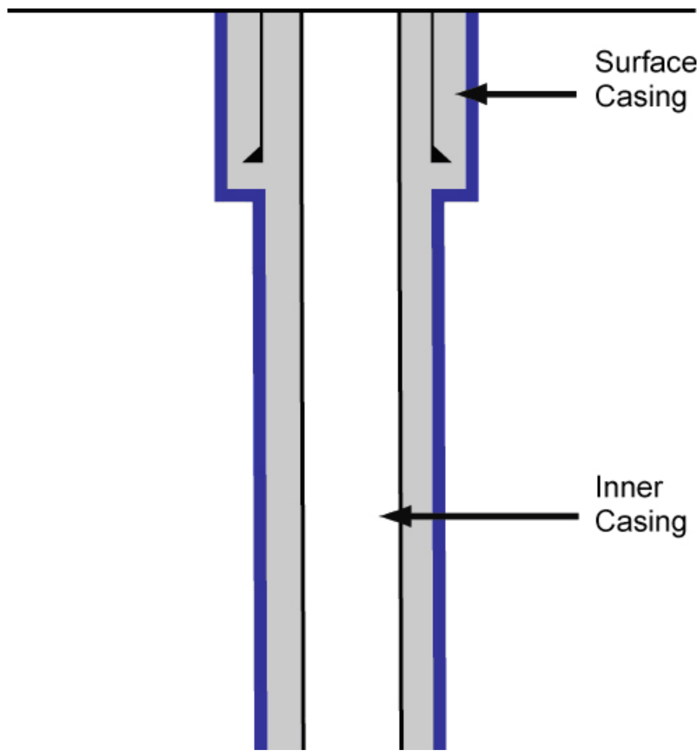


Figure 4-2: Generic Well Schematic for Holes and Wells

For each well, a completed application for permit to drill package will be submitted to the appropriate regulatory agencies for approval at the time each well location is identified.

4.9 THE AMOUNT/TYPE OF CEMENT USED IN SETTING EACH CASING STRING

Wells will be designed, cased, and cemented per applicable regulations; potential freshwater zones will be isolated. Determination of cement volumes will be made with the assumption that surface casing and "production" casing will be cemented back to surface. Typical slurry volumes are 50 ft^3 for surface casing and 500 ft^3 for production casing. Cements will be neat slurries of Class G cement with silica added to provide thermal stability.

5 A NARRATIVE WHICH ADDRESSES THE ENVIRONMENTAL ASPECTS ASSOCIATED WITH THE PROPOSED PROJECT WHICH INCLUDES, AT A MINIMUM, THE FOLLOWING

5.1 WATER RIGHTS, AN ESTIMATE OF THE QUANTITY OF WATER TO BE USED, (DETAILED YEARLY AND PROJECT TOTAL)

While the actual freshwater requirements for this process are not fully known, it is expected that freshwater requirements will be lower than 1980s estimates of two to five barrels of water per barrel of oil produced for mining and retorting operations (Bartis et al., 2005). The consumptive freshwater requirements to cool and reclaim spent shale do not apply to *in situ* methods. Water will be needed for construction and drilling activities, shale oil processing, dust control, testing the recovery of sodium minerals, and if necessary, used to mitigate groundwater contamination, if any. Instantaneous water requirements will vary depending on the nature of on-going operations (drilling, initial heating, production, nahcolite recovery, and reclamation). To the extent practical, ExxonMobil will treat water for reuse and will plan field operations in phases such that peak requirements for water (and other resources such as power) are moderated.

ExxonMobil's current estimates of freshwater use on the RD&D lease are provided in Table 5-1. It is expected that the water use per barrel of oil produced for a commercial development would be significantly less than the research, development, and demonstration efforts described herein.

Table 5-1: Water Use Estimates for RD&D Lease

Year	Fresh Water Estimates (kbbl/yr)
1	19-39
2	24-50
3	22-80
4	24-55
5	26-82
6	25-55
7	4-11
8	4-11
9	4-11
10	4-11
Average	15.6-40.5

Work on the RD&D lease will help to better define water needs for commercial *in situ* oil shale development and may identify opportunities to reduce water use.

The source of fresh water for the project is anticipated to be ExxonMobil's existing water rights within the region. ExxonMobil Exploration Company and its affiliated sister companies own surface and ground water rights within the Piceance Basin. The closest potential EM water source to the proposed lease tract includes the Love Ranch and B&M Reservoir ponds which receive water from Piceance Creek under an existing water right

(98CW0259). As the project is research in nature, it has not been determined that the Love Ranch and B&M Reservoir ponds would definitely be the project water source.

5.2 TYPES OF PRODUCTS AND BY-PRODUCTS, STORAGE/DISPOSAL OF PRODUCTS PRODUCED FROM THE PROCESS, AND POLLUTANTS THAT MAY ENTER ANY RECEIVING WATERS SURFACE OR GROUND

Produced oil will be collected, analyzed, used for processing experimentation, stabilized (as needed), and trucked offsite for appropriate disposal or sale. The quantity of oil available for potential sale is not expected to be sufficient to support a commercial operation. Onsite tankage will be used to temporarily store oil prior to loading onto trucks.

Produced gas will be analyzed and may be processed to remove H_2S. The remaining gas will likely be consumed onsite, incinerated, flared, or piped to local gas gathering lines for further offsite processing.

Produced water will be analyzed and used for processing experimentation, stripped of H_2S and trucked offsite for appropriate offsite disposal. The feasibility of these options will be evaluated based on the current available infrastructure at the time of detailed design. Processed produced water may be temporarily stored in onsite tankage prior to loading onto trucks.

Sulfur recovered from gas treating and produced water stripping, will be stored onsite in appropriate storage units, until loaded onto trucks for appropriate offsite disposal or sale. An incinerator may be used for final offgas treating to control CO and NOx emissions.

No pollutants are expected to be released into surface or groundwaters. Spill prevention measures will be in place to prevent, mitigate, and control any spills. The stormwater drainage system is expected to minimize potential to allow contact between runoff and any process fluids or products. Drilling mud pits are to be designed to minimize potential for discharge of drilling fluids other than for collection and appropriate disposal.

5.3 SPILL PREVENTION CONTROL AND COUNTERMEASURES (SPCC)

A site specific SPCC Plan will be created for surface disturbance and a copy provided to BLM.

Substances that pose a risk of harm to human health or the environment shall be stored in appropriate containers. Fluids that pose a risk of harm to human health or the environment, including but not limited to produced water, shall be stored in appropriate containers and in secondary containment systems at 110% of the largest vessel’s capacity. Secondary fluid containment systems shall be lined with a minimum 24 mil impermeable liner.

5.4 PREVENTION/REMEDIATION PLAN FOR GROUNDWATER CONTAMINATION

Our mitigation strategy to protect proximate groundwater (and by extension, the surface water streams in communication with groundwater) will be to design the operations to contain the process affected zone in a low-permeability envelope of unheated oil shale. The effectiveness of this strategy will be evaluated throughout the research operations with a comprehensive Groundwater Monitoring Program.

5.4.1 GROUNDWATER PROTECTION STRATEGY – HYDRAULIC ISOLATION APPROACH

ExxonMobil proposes to design its field development such that the pyrolysis and production zone is isolated from proximate aquifer(s). As part of the appraisal well program, small water fracs are planned in the stratigraphic zones in and around the target heating zone. These small fracs will provide local fracture orientation and the magnitude of in situ stress. The orientation and stress state information will be used to plan heaters and limit them to the target heating zone. Thus, an impermeable seal will be maintained around the developed volume (Figure 5-1).

In the configuration shown in Figure 5-1, the notional top of the target heating zone is anticipated to be ~2300 – 2750 ft below surface. Such a development strategy should preclude contact between proximate groundwater sources and the process zone. Geomechanical modeling indicates that the process volume can be surrounded by cold pillars of oil shale such that subsidence and associated faulting could be mitigated, preventing connection to over- or underlying aquifers.

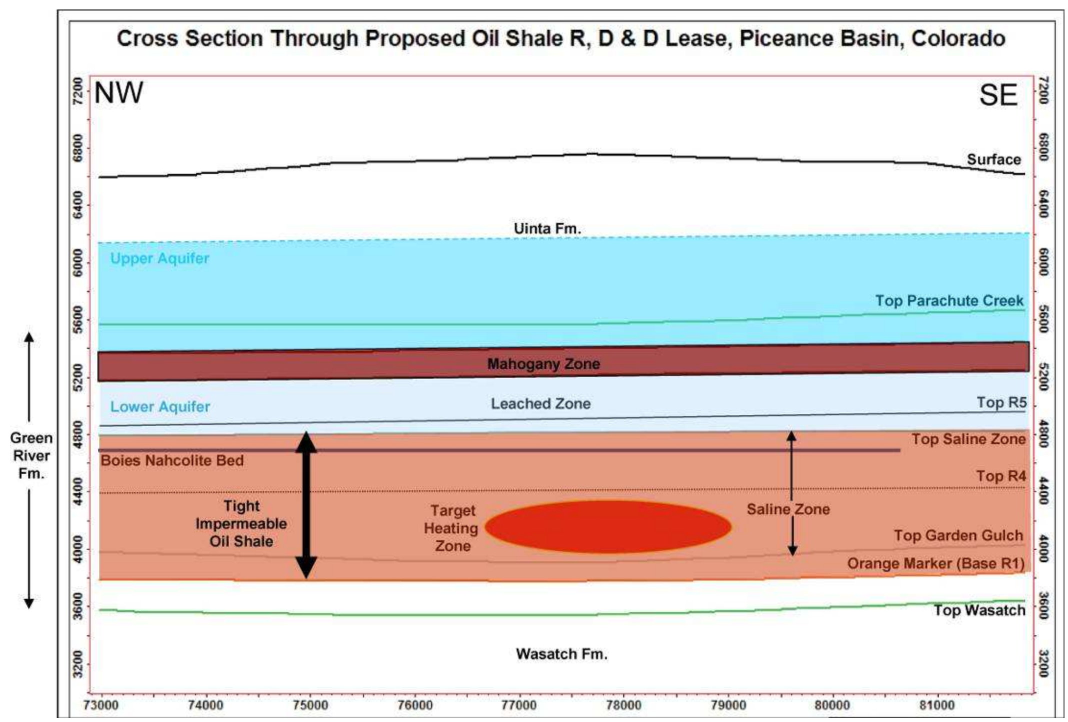


Figure 5-1: Schematic Depiction of ExxonMobil's Hydraulic Isolation Approach to Mitigating Groundwater Contamination from the Pyrolysis Zone

5.4.2 GROUNDWATER MONITORING

Groundwater monitoring will take place quarterly beginning 15 months prior to the start of pyrolysis operations and extend through a period of 2 years after the pilot is completed. See Section 5.7.1 for details.

5.4.3 REMEDIATION PLAN

Should groundwater monitoring indicate contamination, the pyrolyzed zone could be flushed with water through the production wells to remediate.

5.5 A DESIGN FOR THE NECESSARY IMPOUNDMENT, TREATMENT OR CONTROL OF ALL RUNOFF WATER AND DRAINAGE FROM DISTURBED AREAS TO REDUCE SOIL EROSION AND SEDIMENTATION AND TO PREVENT THE POLLUTION OF RECEIVING WATERS (STORMWATER MANAGEMENT PLAN)

5.5.1 STORMWATER MANAGEMENT PLAN

A comprehensive Stormwater Management Plan will be developed to mitigate sediment impacts from stormwater runoff caused by erosion, which may include segregating topsoil material and implementing erosion and sediment control measures on slopes exceeding 5%. This Plan will be submitted to the BLM and the State of Colorado.

In general, drainage and diversion of stormwater will be around and off the facilities to mitigate any erosion to site facilities and surrounding areas. It is not anticipated that a stormwater runoff retention pond will be used.

5.6 A DETAILED DESCRIPTION OF MEASURES TO BE TAKEN TO PREVENT OR CONTROL FIRE, AND THE BEST MANAGEMENT PRACTICES (BMPS) UTILIZED TO PREVENT SOIL EROSION, SUBSIDENCE, POLLUTION OF SURFACE AND GROUND WATER, POLLUTION OF AIR, DAMAGE TO FISH OR WILDLIFE OR OTHER NATURAL RESOURCES AND HAZARDS TO PUBLIC HEALTH AND SAFETY

5.6.1 PREVENT OR CONTROL FIRE

When working on lands administered by White River Field Office, ExxonMobil will notify Craig Interagency Dispatch (970-826-5037) in the event of any fire. The reporting party will inform the dispatch center of the location of the fire, size, status, smoke color, aspect, fuel type and contact information. The reporting party or a representative would remain nearby in order to make contact with incoming fire resources to expedite actions taken towards an appropriate management response. The applicant and contractors will not engage in any fire suppression activities outside the approved project area. Accidental ignitions caused by welding, cutting, grinding, etc. will be suppressed by the applicant only if employee safety is not compromised and if the fire can be safely contained using hand tools and portable hand pumps. If chemical fire extinguishers are used, the applicant would notify incoming fire resources of the extinguisher type and the location of use. Natural ignitions caused by lightning will be managed by federal fire personnel. If a natural ignition occurs within the approved project area, the fire may be initially contained by the applicant only if employee safety is not compromised. The use of heavy equipment for fire suppression is prohibited, unless authorized by the Field Office Manager. Moreover, removal of slash and woody debris associated with the proposed action shall follow mitigations as written under Forest Management.

5.6.2 PREVENT POLLUTION OF AIR

Access roads will be treated with water and/or other approved dust suppressant during construction and drilling activities to minimize dust trails behind vehicles. Vehicles will abide by company or public speed restrictions during all activities. If water is used as a dust suppressant, there would be no traces of oil or solvents in the water, and it would be properly permitted for this use by the State of Colorado. Only water needed for abating dust would be applied.

Onsite incineration will be performed to mitigate generation of CO and NO_x. It is expected that sulfur containing compounds and hydrocarbons would be retained within the process system, and only flared in emergency situations.

The largest air emission is expected to be CO_2, as vent gas and exhaust from hydrocarbons combusted onsite. The emergency flare is expected to oxidize all sour gases and natural gas that must be relieved from the processing system, in the event of an emergency.

5.6.3 PREVENT SOIL EROSION, SUBSIDENCE

In order to protect rangeland health standards for soils, if erosion features (i.e. riling, gullying, piping and mass wasting on the surface disturbance or adjacent to the surface disturbance) occur as a result of this action, they will be addressed immediately upon observation, by first contacting the authorized officer and then submitting a plan to assure successful soil stabilization with best management practices (BMPs) to address erosion problems

ExxonMobil will locate culverts or drainage dips in such a manner to avoid discharge onto unstable terrain such as headwalls or slumps; provide adequate spacing to avoid accumulation of water in ditches or road surfaces; install culverts with adequate armoring of inlet and outlet; patrol areas susceptible to road or watershed damage during periods of high runoff; keep road inlet and outlet ditches, catch basins, and culverts free of obstructions, particularly before and during spring run-off. Culverts and waterbars will be installed according to BLM Manual 9113 standards and sized for the 10-year storm event with no static head, and to pass a 25-year event without failing.

BMPs associated with stormwater management / erosion control will be applied to the site during construction & drilling/ completion operations. Wattles may be used for perimeter runoff control around the location and stockpiles. Following construction, the need for temporary stabilization measures for cut/ fill slopes will be evaluated based upon rock content and degree of slope. In areas of rock content > 50%, no erosion control measures on slopes will be implemented, and primary BMP will be wattles at the toe of the fill slope. Where < 50% rock content, surface roughening and erosion control blankets may be used to stabilize the fill slopes. If field conditions do not allow for effective surface roughening or installation of erosion control blankets, hydromulching may be used. If hydromulching is used, the seed will be sprayed at double the drill seeding rate followed by application of hydromulch.

ExxonMobil will employ, maintain, and periodically update to the best available technology(s) prescribed by regulations aimed at reducing emissions, fresh water use and hazardous material utilization, production and releases through all phases of development and production.

5.7 A DETAILED DESCRIPTION OF MONITORING THE DEVELOPMENT PROCESS, SURFACE WATER, GROUNDWATER (SURFACE/GROUNDWATER MONITORING AND RESPONSE PLAN), AIR EMISSIONS, AIR QUALITY, AND PROPOSED NOISE ABATEMENT PROCEDURES / EQUIPMENT

5.7.1 GROUNDWATER MONITORING PROGRAM

ExxonMobil will contract a qualified hydrogeological and/or hydrology consultant firm (in addition to using in-house experts) to develop a comprehensive Surface/Groundwater Monitoring Program prior to the start of operations.

Up to 48 groundwater monitoring wells are planned (subject to change following the findings of preliminary hydrologic surveys), and these wells will be completed in overlying and possibly underlying hydrologic units, both upstream and downstream of the process site. Exact well spacing, depth of well completion, and other pertinent details will be finalized after the subsurface hydrology in and around the process zone is adequately characterized.

The Groundwater monitoring program will begin 15 months prior to the start of pyrolysis operations to obtain baseline data on groundwater quality. A complete list of constituents for groundwater monitoring is provided in Table 5-2. Groundwater monitoring well samples will be collected on a quarterly basis and analyzed by a Colorado state-certified laboratory. Analytical results will be recorded and reported to the appropriate agencies at an agreed upon format and frequency.

Table 5-2: List of Constituents for Groundwater Monitoring Plan

Constituent	Units	Constituent	Units
Field Measurements		*Trace Constituents – Inorganic (Lab)*	
pH		Arsenic	mg/L
Temperature	°C	Boron	mg/L
Dissolved Oxygen	mg/L	Chromium, Hexavalent	mg/L
Turbidity	ntu	Chromium, Total	mg/L
Conductivity[1]	µmho/cm	Iron	mg/L
Arsenic[2]	mg/L	Lead	mg/L
Ammonia[1]	mg/L	Lithium	mg/L
COD[1]	mg/L	Molybdenum	mg/L
General Water Quality (Lab)		Nickel	mg/L
Alkalinity (as $CaCO_3$)	mg/L	Potassium	mg/L
Hardness (as $CaCO_3$)	mg/L	Selenium	mg/L
TDS	mg/L	Sodium	mg/L
TOC	mg/L	Strontium	mg/L
Calcium	mg/L	Zinc	mg/L
Ammonia	mg/L	*Trace Constituents – Organic (Lab)*	
TKN	mg/L	Benzene	µg/L
Bicarbonate	mg/L	Toluene	µg/L
Fluoride	mg/L	Ethylbenzene	µg/L
Chloride	mg/L	Xylenes	µg/L
Phosphate	mg/L	TPH	mg/L
Sulfate	mg/L	Phenols	mg/L
Sulfide	mg/L		

[1]Using a Hach DR5000 with accessories for measuring COD and ammonia
[2]Using a Lamotte portable Rapid Arsenic Test Kit (detection limit of 0.2 µg/L)

In an effort to enhance the overall effectiveness of our monitoring program, ExxonMobil has identified chemical species found in both groundwater and wastewaters from oil shale pyrolysis operations that can serve as surrogate indicators for potential groundwater contamination. ExxonMobil performed a literature review of wastewaters from oil shale operations (Jackson et al., 1975; Harding et al., 1977; Fox et al., 1978; Fox and Phillps, 1980; Jones et al., 1980, 1982; Mukhopadhyay and Fosbery, 1982; Torpy et al., 1982; Day et al., 1983; and Bates et al., 1984) and identified certain constituents, such as ammonia, conductivity, chemical oxygen demand (COD) and sulfide that appear at higher concentrations in pyrolysis and/or leachate wastewaters than would normally be expected in groundwater under ambient conditions. A key consideration when identifying such constituents was the capability for field measurement using portable field test kits to enable rapid detection/quantification. These four surrogates will be measured more frequently to allow for early detection of contaminants in proximate groundwaters. If an increasing concentration trend in these surrogates is observed, a full suite of samples will be collected for analysis by the contracted laboratory, appropriate mitigation identified, and groundwater remediated as necessary. Analytical results from field measurements will be compared with results obtained from the contracted laboratory for validation and calibration.

As part of the groundwater monitoring program, ExxonMobil may perform tracer tests to determine the general direction of groundwater flow and velocity. Depending on the results of the hydrologic surveys at the test site, multiple tracer tests may be performed with injection (tracer) points in strata above and below the process affected zone. A detailed design of the tracer tests will be prepared and submitted to the appropriate regulatory agencies for approval. The type of tracer, mode of injection (slug or continuous), and other pertinent details will be specified in the design of the tracer study. The tracer tests will be performed after the groundwater monitoring system is in place.

The comprehensive Groundwater Monitoring Program proposed by ExxonMobil will serve to determine the efficacy of the previously described hydraulic isolation approach and to detect groundwater contamination outside of the pyrolysis and production zones. If these measurements indicate that constituents of concern are detected in unacceptable levels outside the production zone, operations will be modified to prevent further contamination, and steps will be taken to remediate the groundwater.

5.7.2 Surface Water Protection & Interim Mitigation Plan

Potential impacts to surface water quality from stormwater runoff may be caused by sediments from erosion of disturbed land areas and by contact with surface processing facilities. ExxonMobil’s plan for mitigating surface water impacts from these two sources is described in the following sections.

5.7.3 Surface Water Monitoring Plan

A comprehensive Surface Water Monitoring Plan will be developed prior to the start of operations (and in parallel to the development of the Groundwater Monitoring Program) to detect potential contaminants migrating from the pyrolysis zone. The Surface Water Monitoring Plan will be implemented approximately 15 months prior to beginning the pyrolysis operations and will include, at a minimum, four sampling locations: two in Ryan Gulch and two in Yellow Creek, one upstream and one downstream of operations in each creek. Additional surface water sampling and monitoring sites may be included as more information becomes available. A list of proposed measurements and constituents for the Surface Water Protection Plan is included in Table 5-3.

Table 5-3: List of Constituents for Surface Water Monitoring Plan

Constituent	Units	Constituent	Units
Field Measurements		*Trace Constituents – Inorganic (Lab)*	
pH		Arsenic	mg/L
Dissolved Oxygen	mg/L	Boron	mg/L
Conductivity[1]	μmho/cm	Chromium, Hexavalent	mg/L
Arsenic[2]	mg/L	Chromium, Total	mg/L
Ammonia[1]	mg/L	Iron	mg/L
COD[1]	mg/L	Lead	mg/L
General Water Quality (Lab)		Lithium	mg/L
Alkalinity (as $CaCO_3$)	mg/L	Molybdenum	mg/L
Hardness (as $CaCO_3$)	mg/L	Nickel	mg/L
TDS	mg/L	Potassium	mg/L
TOC	mg/L	Selenium	mg/L
Calcium	mg/L	Sodium	mg/L
Ammonia	mg/L	Strontium	mg/L
TKN	mg/L	Zinc	mg/L
Bicarbonate	mg/L	*Trace Constituents – Organic (Lab)*	
Fluoride	mg/L	Benzene	μg/L
Chloride	mg/L	Toluene	μg/L
Phosphate	mg/L	Ethylbenzene	μg/L
Sulfate	mg/L	Xylenes	μg/L
Sulfide	mg/L	TPH	mg/L
		Phenols	mg/L

[1]Using a Hach DR5000 with accessories for measuring COD and ammonia
[2]Using a Lamotte portable Rapid Arsenic Test Kit (detection limit of 0.2 μg/L)
Note: Unless mentioned otherwise, constituent refers to total concentration, which includes dissolved as well as particulate concentration. Dissolved concentrations may be determined by filtering (in the field) through a 0.45 μm filter.

5.7.4 WASTEWATER

Wastewater will be generated from drilling operations, shale oil production and processing, nahcolite recovery operations, and final reclamation. During the early research stage, the volume of wastewater produced will be relatively small and is planned to be managed by removing H_2S, and trucking the resulting produced water for appropriate offsite disposal. Such water handling operations will comply with state and local regulations and permits. During later research stages, some or all of the wastewater may be treated for reuse by skid-mounted facilities.

For commercial development, ExxonMobil proposes to treat these wastewater streams and recycle them for various process needs. Treating and recycling wastewater will reduce the demand on freshwater resources posed by ExxonMobil's in situprocess. Collection and analysis of water from the RD&D operations will enable ExxonMobil to evaluate various treatment options, optimize unit processes, and establish efficient design criteria for the treatment of these wastewater streams to applicable standards, either for reuse in on-going operations, offsite disposal, or for discharge to a permitted outfall.

5.7.5 AIR EMISSIONS, MONITORING & MITIGATION MEASURES

ExxonMobil will use appropriate technology to mitigate air emissions (including fugitive dust). Our operations will comply with applicable regulations.

Likely sources of project-related air emissions include exhausts from drill rigs, power generating equipment and vehicles and potential fugitive emissions from the surface facilities. Sources of air emissions will be evaluated, and best available control technologies (BACT) will be used as prescribed by regulations, to reduce their impact on air quality. Vehicles and construction equipment will be equipped with emission controls to reduce fugitive hydrocarbon emissions (uncombusted fuel) and particulate matter. Pursuant to a site-specific environmental analysis, a comprehensive Air Emissions Monitoring Program will be developed to detect emissions of hydrocarbons (VOCs), carbon monoxide (CO), nitrogen oxides (NOx), sulfur oxides (SOx), hydrogen sulfide, ammonia, and particulate matter (PM). ExxonMobil intends to use external consultants or in-house experts to perform atmospheric dispersion modeling to determine adherence to the National Ambient Air Quality Standards (NAAQS).

5.7.6 FUGITIVE DUST EMISSIONS AND MITIGATION MEASURES

Major sources of fugitive dust emissions include construction activities, paved and unpaved roads, and unenclosed storage piles. Major factors that determine the transport of dust plumes include soil condition, wind speed, and vehicular traffic. ExxonMobil will use industry best practices to reduce fugitive dust emissions from vehicular traffic and surface disturbance. Potential mitigation measures include maintaining appropriate speed limits, road cleaning and/or resurfacing for paved roads, and water spraying of unpaved roads.

5.7.7 NOISE ABATEMENT PLAN

Compressors and pumps will be electric motor-driven to mitigate noise. Portable generators, if needed, will have noise control equipment installed to meet noise requirements at the lease boundary. Normal construction equipment will be used for surface disturbance. Drill rigs will be used to drill appraisal wells, monitor wells, production wells, observation holes. Rigs will meet current noise abatement regulations.

6 A RECLAMATION SCHEDULE AND THE MEASURES TO BE TAKEN FOR SURFACE RECLAMATION OF THE RD&D TRACT THAT WILL ENSURE COMPLIANCE WITH THE ESTABLISHED REQUIREMENTS

ExxonMobil will return disturbed areas to approximate original contour and rehabilitate the road and location to a satisfactorily revegetated, safe and stable condition per BLM specifications. If final reclamation requires disturbance > 1 acre, stormwater permit coverage under the State's stormwater program will be reopened.

Mud pits will be reclaimed per applicable regulations. Up to two types of ponds may be required: one to store fresh water for drilling and completions, construction, and dust control and another for storage of produced water. Alternatively, dedicated tanks may be used for storing produced and/or fresh water.

In addition to pits for drilling and completions, we may use truck-mounted, temporary steel tanks (400-500 bbl) or temporary contractor-supplied above-ground steel drilling pits (10 ft x 30 ft x 6 ft deep) with a secondary containment berm.

Natural drainage patterns will be restored and stabilized by application of BMPs per approved SWMP for this site. These BMPs include surface roughening, permanent seeding and may include use of erosion control blankets following regrading operations. Storm runoff from the regraded areas will continue to be controlled using wattles and other appropriate BMPs until stabilization of the reclaimed area has been achieved.

Stockpiled soil will be incorporated into the regraded area in locations available for final recontouring. Shale/rock will be placed in the lower portions of filled areas as appropriate. Following regrading, areas compacted by earthworks will be scarified to a minimum depth of 6" and the stockpiled topsoil will be distributed evenly across the reclaimed area.

Following topsoil placement, the seedbed will be prepared by disking or ripping. The area will be seeded with the approved BLM seed mixture. Seed will be certified and free of noxious weeds. Seed certification tags will be submitted to the area manager. Seed will be drilled 'on contour' to a depth no greater than ½". In areas too steep to operate the seed drill, seed will be broadcast at double the seeding rate and harrowed into the soil. Alternatively, hydromulching may be used in these areas. If hydromulching is used, the seed will be applied first at double the seeding rate prior to hydromulch application.

Depending upon the location of the surface disturbance, Exxon Mobil will use the seed mixes listed below in Table 6-1 (provided by WRFO BLM). The rolling loam sites would be seeded with mix 2 and the pinyon juniper sites would be seeded with mix 3. If the plot spans two range sites, BLM would probably recommend the seed mix of the majority site.

Table 6-1: BLM Seed Mixes

Seed Mix	Cultivar	Species	Scientific Name	Application Rate (lbs PLS/acre)
2	Arriba	Western Wheatgrass	*Pascopyrum smithii*	4
	Rimrock	Indian Ricegrass	*Achnatherum hymenoides*	3.5
	Whitmar	Bluebunch Wheatgrass	*Pseudoroegneria spicata ssp. inermis*	4
	Lodorm	Green Needlegrass	*Nassella viridula*	2.5
	Timp	Northern Sweetvetch	*Hedysarum boreale*	3
		Sulphur Flower	*Eriogonum umbellatum*	1.5
	Alternates:*			
	Critana	Needle and Thread	*Elymus lanceolatus ssp. lanceolatus*	3
		Scarlet Globemallow	*Sphaeralcea coccinea*	0.5
3	Rosanna	Western Wheatgrass	*Pascopyrum smithii*	4
	Whitmar	Bluebunch Wheatgrass	*Pseudoroegneria spicata ssp. inermis*	3.5
	Rimrock	Indian Ricegrass	*Achnatherum hymenoides*	3
		Needle and Thread Grass	*Hesperostipa comata ssp. comata*	2.5
	Maple Grove	Lewis Flax	*Linum lewisii*	1
		Scarlet Globemallow	*Sphaeralcea coccinea*	0.5
	Alternates:*			
	Critana	Thickspike Wheatgrass	*Elymus lanceolatus ssp. lanceolatus*	3
		Sulphur Flower	*Eriogonum umbellatum*	1.5

Slopes of gradient 3:1 (33%) or steeper will be covered with wildlife-friendly biodegradable fabrics (such as, but not limited to, jute blankets, Curlex, etc.). Following seeding and placement of biodegradable fabrics (as required), woody debris cleared during initial construction will be pulled back over the recontoured/ partially reshaped areas to act as flow deflectors and sediment traps. Available woody debris will be evenly distributed so as not to account for more than 20% of total ground cover (or 3 – 5 tons/ acre).

After reclamation is concluded, livestock grazing will be excluded from reclaimed portions by installation of a four-strand BLM Type-D barbed wire fence with braced wooden corners. Once reclaimed plant species are fully established, the fence will be removed after a minimum of 2 growing seasons. Additional reclamation efforts will be undertaken if, after the first growing season, there are no positive indicators of successful establishment of seeded species (i.e. germination).

BMPs during reclamation will include surface roughening, seeding and erosion control blankets. Runoff from the regraded areas will continue to be controlled at the perimeter of the disturbed area using wattles. These measures will continue to be maintained around the perimeter of the site until stabilization of the reclaimed areas has been achieved.

Noxious weed control will be performed 1 – 2 times annually (during the growing season). Applications will be performed by a certified pesticide applicator.

7 THE METHOD AND TIMING OF ABANDONMENT, INCLUDING PROPOSED WELL ABANDONMENT PROCEDURES, AND REMOVAL OF SURFACE STRUCTURES ON RD&D TRACT

Once it has been determined that a well has no further use, nonpermanent downhole equipment will be retrieved (e.g., pumps used for production wells) and the well will be cemented back to surface to prevent migration of fluid within the casing. During the experimental phases of the project, we anticipate that instrumentation (e.g., temperature, geophones, etc.) will be cemented in several of the monitoring wells. These wells will be left in their previously completed state with cement added to fill their casing back to surface where necessary. Casing will be cut off below grade and a P&A marker with well data will be installed.

For Phase II small scale tests, abandonment operations are expected to begin in, and possibly extend beyond, year 4.

For Phase III pilot, abandonment operations are expected to begin in, and possibly extend beyond, year 10.

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